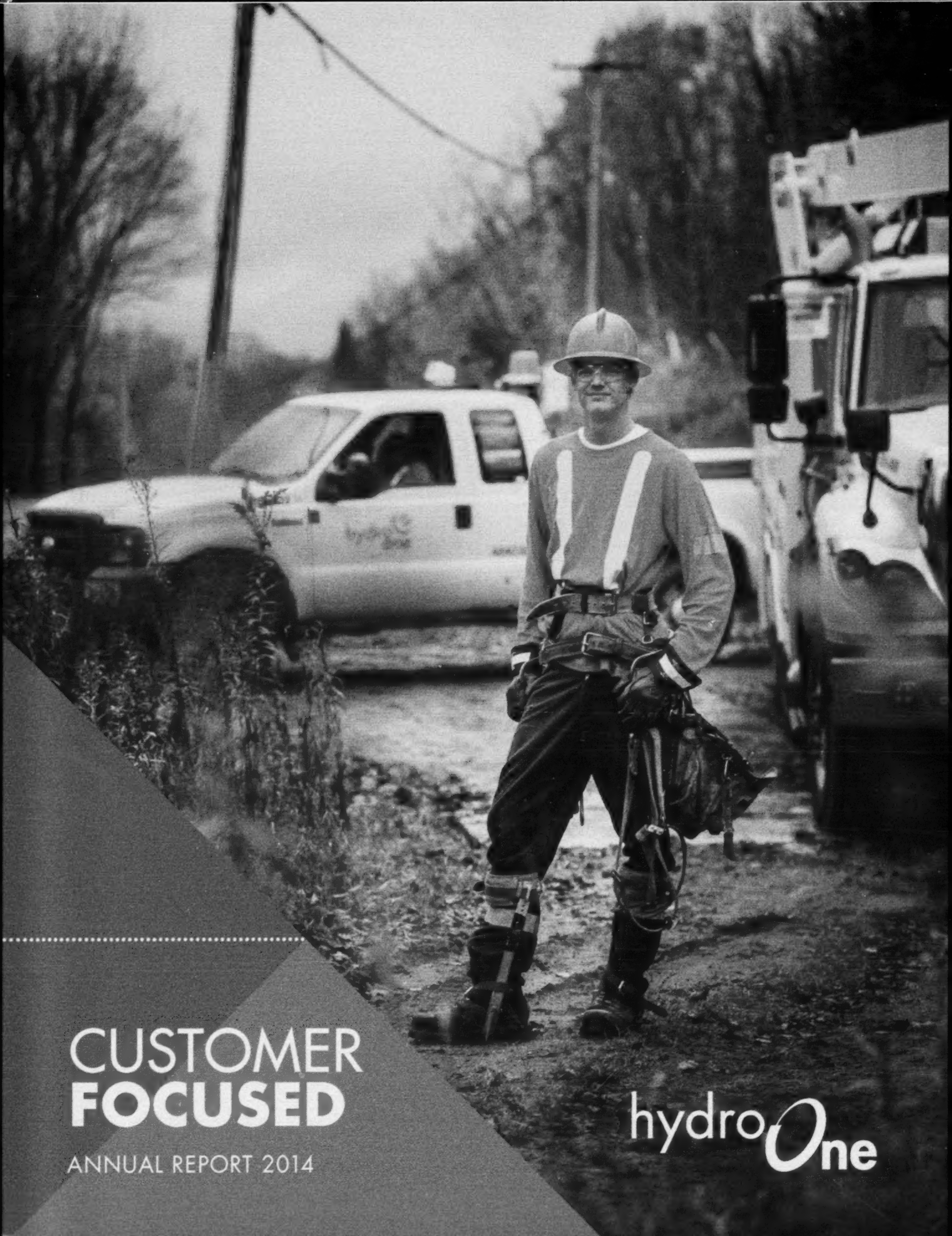


CUSTOMER FOCUSED

ANNUAL REPORT 2014

hydroOne

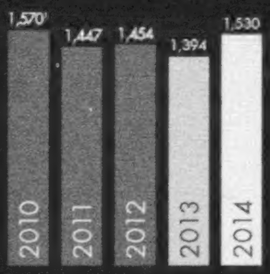
We are customer focused, from the inside out. In our delivery of safe, reliable and responsible power, we know that we must look to our customers' needs in everything we do. **More than 1.3 million homes and businesses across Ontario rely on us. And we will deliver.**

OUR FOCUS

CONSOLIDATED FINANCIAL HIGHLIGHTS AND STATISTICS

CAPITAL INVESTMENTS

(CAD $ millions)

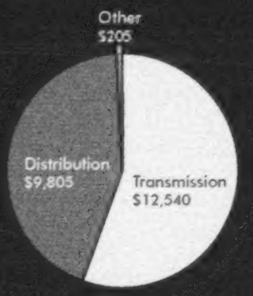


[1] based on Canadian GAAP

TOTAL ASSETS

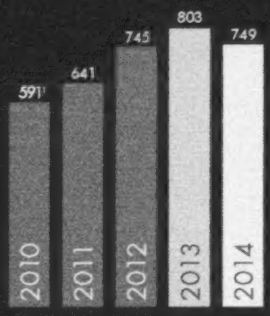
December 31, 2014

(CAD $ millions)



NET INCOME

(CAD $ millions)



[1] based on Canadian GAAP

1.8

recordable injuries per 200,000 hours worked, a decrease from 2.5 in 2013

12,000 km

The Electricity Discovery Centre travelled more than 12,000 kilometres between September 2013 and September 2014

$224 m

In 2014, Hydro One invested more than $224 million in Ontario's transmission system to increase electricity reliability in Toronto and the Greater Toronto Area

60,000

Hydro One spoke to more than 60,000 customers during three tele-townhalls in 2014

TABLE OF CONTENTS

Letter from the Chair 2
Letter from the President and CEO 4
Customer Service 6
Safety 8
Reliability 10
Execution Excellence 12
Senior Management 14
Management's Discussion and Analysis 15
Management's Report 64
Independent Auditors' Report 65
Consolidated Statements of Operations and Comprehensive Income 66
Consolidated Balance Sheets 67
Consolidated Statements of Changes in Equity 69
Consolidated Statements of Cash Flows 70
Notes to Consolidated Financial Statements 71
Community 114
Board of Directors 116

IS ON YOU

Year ended December 31 *(CAD $ millions, except as otherwise noted)*	2014	2013	Change	% Change
Revenues	**6,548**	6,074	474	8
Purchased power	**3,419**	3,020	399	13
Operating costs	**1,914**	1,782	132	7
Net income	**749**	803	(54)	(7)
Net cash from operating activities	**1,256**	1,404	(148)	(11)
Average annual Ontario 60-minute peak demand *(MW)*[1]	**20,596**	21,493	(897)	(4)
Distribution – units distributed to our customers *(TWh)*[1]	**29.8**	29.8	–	–

[1] System-related statistics are preliminary.

LETTER FROM THE CHAIR

> "Of all the firsts in 2014, the one that speaks to me the most is the commercial partnership between our Company and the Saugeen Ojibway Nation to own the Bruce to Milton transmission line. This is the first time in the Company's history that we have partnered with a First Nation on a commercial basis."

The people of Ontario count on Hydro One to reliably deliver the electricity necessary for their families, their businesses and their communities to thrive. They also count on Hydro One to operate effectively in a commercial fashion and make a vital financial contribution to the Province of Ontario, its sole shareholder.

In 2014, the Company focused its efforts on improving customer service, enabling the connection of new energy sources and making the right investments to ensure that Ontario's grid is strong today and ready for the future.

From a financial standpoint, Hydro One's net income in 2014 reached $749 million, with revenues of $6,548 million for the year.

Our 2014 revenues increased by $474 million compared to 2013's revenues of $6,074 million. The increase was due to higher Ontario Energy Board-approved 2014 transmission rates, the recovery of higher purchased power costs, and the OEB's approval of increased export service revenues in recognition of higher electricity exports to other jurisdictions.

Hydro One paid dividends of $287 million to the Province in 2014.

One of the Company's top priorities in 2014 was improving Hydro One's level of customer service. A number of internal and external initiatives across the Company were introduced, including Hydro One's Customer Service Advisory Panel and a customer consultation process to ensure we made things right for our customers.

There were many firsts for the Company in 2014 in the areas of research and innovation. For example, we acquired two unmanned aerial vehicles for our Kleinburg Training Centre. These drones will be primarily used for training purposes and work to use them to test our transmission lines is underway across various departments.

Of all the firsts in 2014, the one that speaks to me the most is the commercial partnership between our Company and the Saugeen Ojibway Nation to own the Bruce to Milton transmission line. This is the first time in the Company's history that we have partnered with a First Nation on a commercial basis.

I would like to thank all Hydro One employees, senior management and my colleagues on the Board for their dedication and commitment to the Company and the people of Ontario.

SPupatello

Sandra Pupatello
Chair of the Board of Directors

LETTER FROM THE PRESIDENT AND CEO

> "We are committed to delivering cost-effective service to all our customers and we remain focused on prudent management, efficient operations and improving the customer experience for everyone we serve."

In 2014, Hydro One concentrated on achieving its goal of becoming Canada's leading utility by 2019. How will we know when we have arrived? The true measure of success will be when our customers, shareholder and employees believe we are a company of great people providing real value and safe, reliable and responsible service. We will only get there if we focus on transforming our culture, get better at our jobs every single day and manage our business effectively.

Hydro One's strong financial performance in 2014 demonstrated our commitment to delivering results for our shareholder as well as our dedication to operating a well-managed business.

During 2014, we put tremendous effort into serving our customers and building stronger relationships. Service levels at our call centre and of our billing system are now better than ever and we have set new targets that, when achieved, will put us among the best in the business.

We moved forward on our journey by investing in our system to replace aging assets and put in place new infrastructure required to deliver the electricity that Ontario needs. Our 2014 Transmission Business capital investments included the replacement of end-of-life power transformers at our Pembroke Transmission Station in eastern Ontario, and at our Hanover, Allanburg, Elmira, and Trafalgar transmission stations in southwestern Ontario. We also received an approved Environmental Assessment to construct the Clarington Transformer Station, critical to keeping the lights on for more than one million Ontarians after the Pickering Nuclear Generating Station shuts down in 2020.

Within our distribution business, our 2014 capital investments included replacement of meters and end-of-life wood poles, work within our station and lines programs, new customer connections and upgrades, and system capability reinforcement projects.

Last year, we completed the acquisition of Norfolk Power Inc., an electricity distribution and telecom company located in southwestern Ontario. We have also reached agreements to acquire two more local distribution companies in southwestern Ontario, Woodstock Hydro and Haldimand Hydro. Consolidating our operations with smaller utilities in our service territory will remain an opportunity to drive growth for Hydro One and improve value for our customers.

We are committed to delivering cost-effective service to all our customers and we remain focused on prudent management, efficient operations and improving the customer experience for everyone we serve.

I would like to thank our Board of Directors for their support, my leadership team for their dedication and our employees for their commitment to working safe, working hard and working to change. They wear the Hydro One logo with pride.

Carmine Marcello

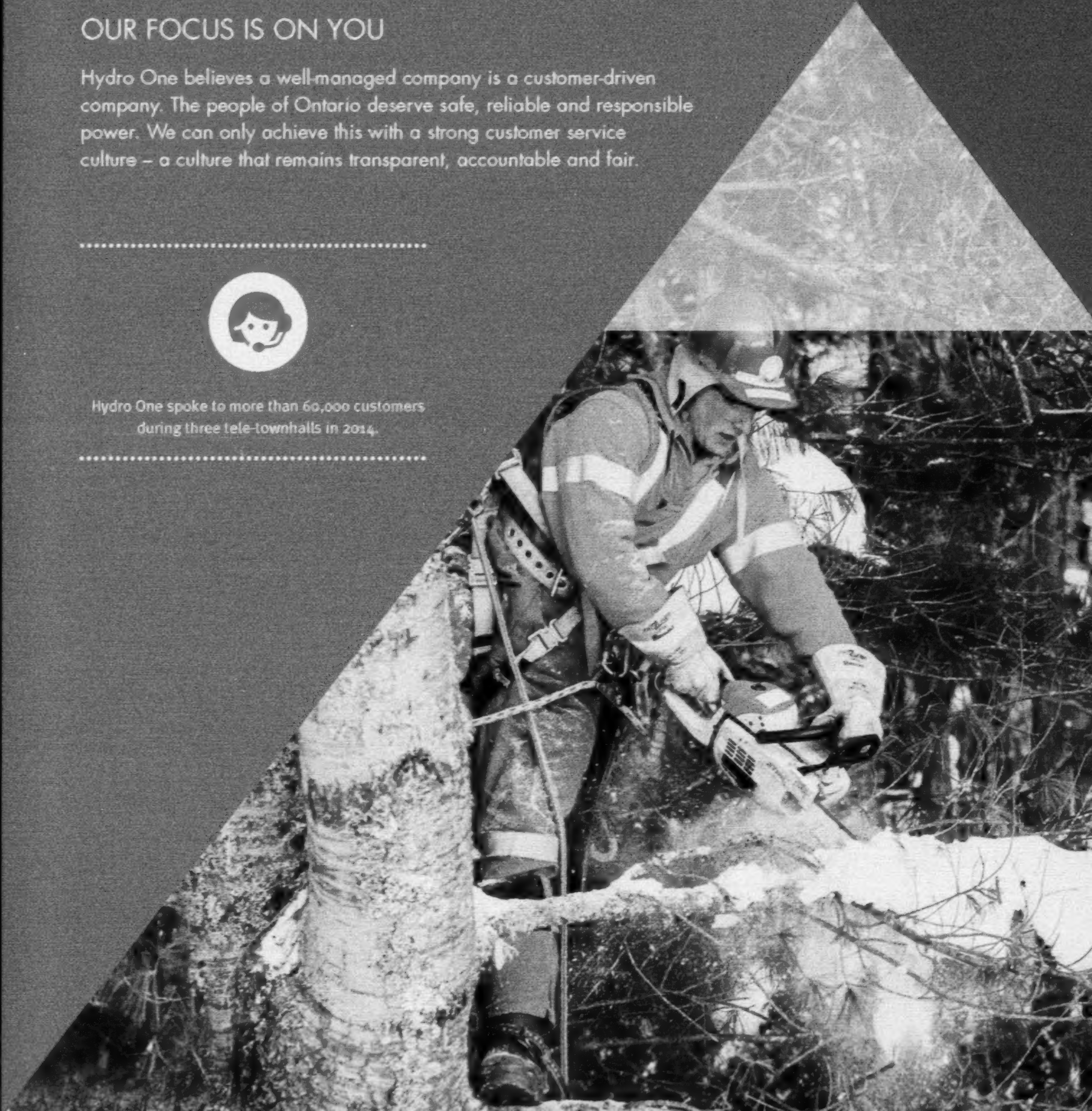
Carmine Marcello
President and Chief Executive Officer

CUSTOMER SERVICE

OUR FOCUS IS ON YOU

Hydro One believes a well-managed company is a customer-driven company. The people of Ontario deserve safe, reliable and responsible power. We can only achieve this with a strong customer service culture – a culture that remains transparent, accountable and fair.

Hydro One spoke to more than 60,000 customers during three tele-townhalls in 2014.



CUSTOMER COMMITMENTS

In 2014, Hydro One hosted three tele-townhalls to reach out to our customers to gather their feedback on how we can serve them better. In the townhalls, we spoke to more than 60,000 customers from across Ontario and the concerns they expressed led to the creation of a customer consultation process in October where we began developing a series of Customer Commitments. We further reached out to customers with our Let's Connect survey to gather additional feedback on our customer service practices.

Join the conversation
Let's Connect
hydro one

CUSTOMER SERVICE ADVISORY PANEL

October also saw the launch of Hydro One's third-party Customer Service Advisory Panel to advise us on how we can improve our customer service culture and deliver on our customer service promises. The body is made up of industry-leading experts from several sectors, including finance, education and technology. The panel meets regularly to assess our performance against stated objectives and holds us accountable for our actions.

CUSTOMER RECOVERY PROCESS

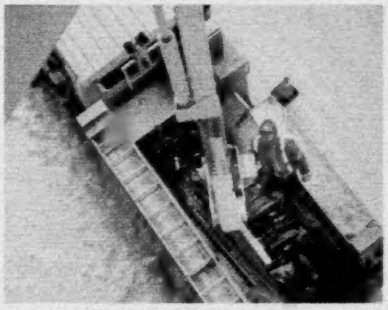
Our path to becoming Canada's leading utility is one of change. In 2014, we introduced major changes across all lines of business to truly become one company. We knew we had to make things right for our customers. In early 2014, at the height of our customer service disruptions with our billing system, approximately 5 per cent of our customers hadn't received a bill for more than three months. By December 2014, that figure had dropped to less than 1 per cent.

Other changes in 2014 to transform our customer service culture included improvements made at our call centre and the launch of a Call-A-Customer program where senior managers from different lines of business contact customers. As well, we revamped our Quality Program in the call centre, with a heightened attention to connecting customers and providing service excellence.

Service levels at our call centre are now better than they were before we implemented our new billing system in May 2013. We have set new targets that, when achieved, will put us among the best in the business. Overall, customer satisfaction has shown a steady increase since early 2014, with a weekly high of 93 per cent of customers satisfied with their call centre interaction.

LINES AND FORESTRY PARTNERSHIP

The year saw a deepening of an already powerful partnership between our Provincial Lines and Forestry Services. What began as a small modification to a zone map has led to a strong partnership that is evident across all levels of the organization. This has resulted in improved customer service, reduced operating costs and shorter storm response times.



REDESIGN OF HYDROONE.COM HOME PAGE

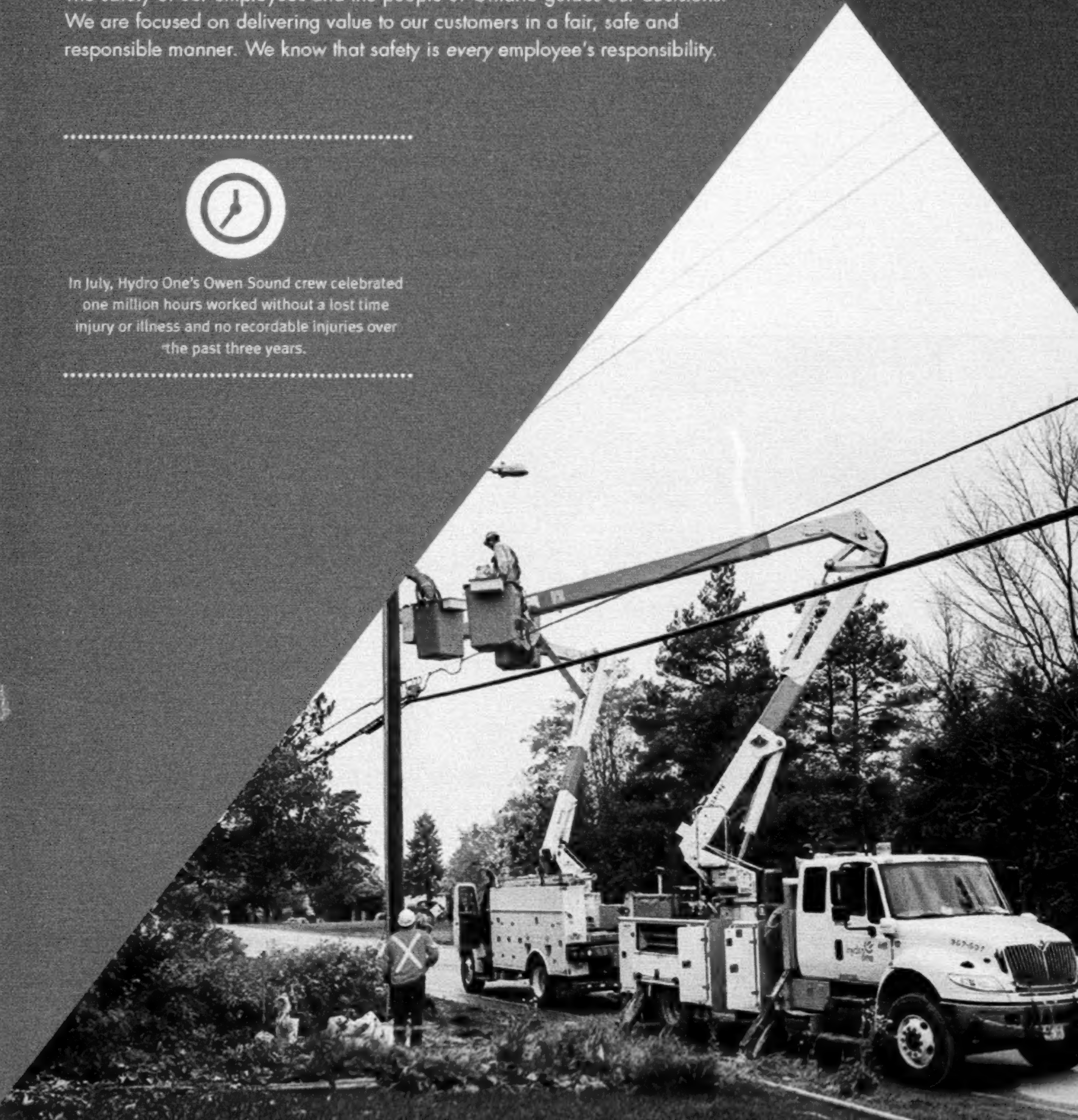
In October, we redesigned the HydroOne.com home page to include a featured stories section to inform our customers about our employees, current projects and the good work we are doing in communities across Ontario.

SAFETY

WE PUT SAFETY FIRST IN EVERYTHING WE DO

The safety of our employees and the people of Ontario guides our decisions. We are focused on delivering value to our customers in a fair, safe and responsible manner. We know that safety is *every* employee's responsibility.

In July, Hydro One's Owen Sound crew celebrated one million hours worked without a lost time injury or illness and no recordable injuries over the past three years.



JOURNEY TO ZERO

Hydro One continued our work with Journey to Zero in 2014, reinforcing employee involvement and engagement by instilling the belief that all injuries are preventable, as well as creating effective Health and Safety communication across the Company and establishing local health and safety goals and objectives.

OHSAS 18001

Hydro One maintained its Occupational Health and Safety Assessment Series (OHSAS) 18001 certification in 2014 due to a continuous improvement strategy to help us prepare for future surveillance audits. The Company was OHSAS 18001 certified in June 2013, demonstrating that we have the elements of a world-class health and safety system in place.

MOVE TO AN INJURY-FREE WORKPLACE

One of our goals is to become a world-class utility by 2019. Our year-end safety performance in 2014 helped us work toward this goal with 1.8 recordable injuries[1] per 200,000 hours worked. That number decreased from 2013 when Hydro One reported 2.5 medical attentions per 200,000 hours worked. The Company has also seen a reduction in both "High MRPH" (Maximum Reasonable Potential for Harm) incidents and the number of preventable motor vehicle accidents in the last few years. In 2014, Hydro One used recordable rates as its corporate safety metric to allow for better performance benchmarking with North American and international industries.

REDUCING DISTRACTED DRIVING

Nothing is more important than the health and safety of our employees and the people of Ontario. Acting on that belief, we introduced a standard in April to prohibit the use of hands-free electronic devices, including smartphones, for all employees who are operating a motor vehicle on Company business. Employees are encouraged to pull over to the side of the road, where it is safe, if they need to handle a call, text or email. The standard takes Section 78.1 of the *Highway Traffic Act* a step further by prohibiting the use of the hands-free options while driving.

BUILDING A SAFE WORKPLACE CULTURE

From proper job planning to a trained and competent workforce, throughout 2014 Hydro One emphasized the importance of a safe workplace culture across all lines of business. The Company introduced nine core principles around its Safe Workplace Vision in 2014. The nine principles focus on continuous improvement and health and safety at Hydro One.

EMPLOYEE ENGAGEMENT

Engaged employees are safer employees. In 2014, we measured employee engagement as it related to our core values, best business practices and health and safety initiatives. Engaged employees had fewer sick days, reported fewer recordable incidents and were less likely to get hurt compared to less engaged employees. Our findings illustrate how strong employee engagement drives our Company's success, enabling us to reach our stated objectives.

OWEN SOUND CREW REACHES SAFETY MILESTONE

In July, Hydro One's Owen Sound crew celebrated one million hours worked without a lost time injury or illness and no recordable injuries over the past three years. The milestone took 14 years to accomplish, and was achieved through proper job planning, teamwork and creating a strong safety culture among all employees.

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[1] A recordable injury is a work-related injury or illness that results in:

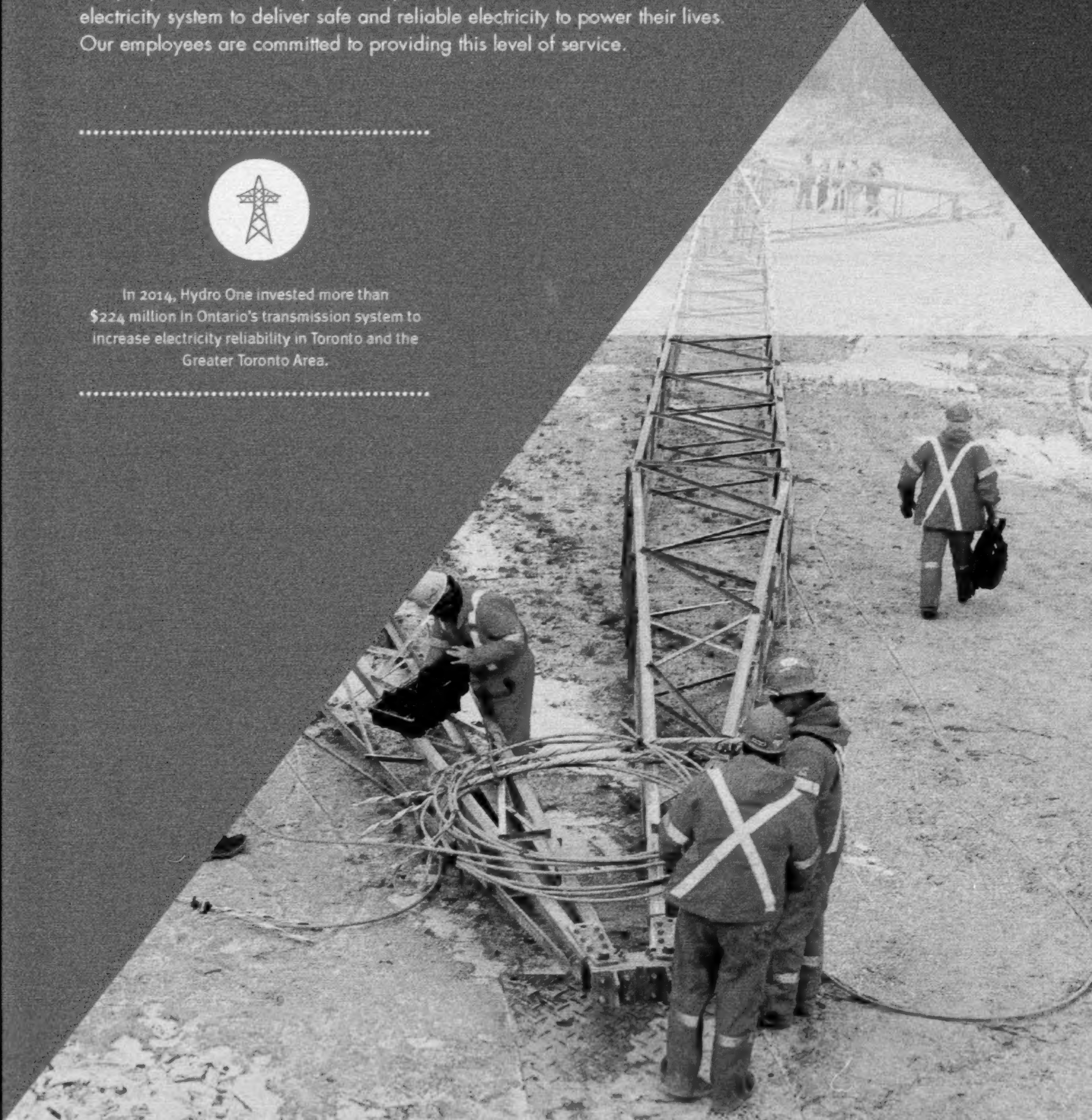
- Restricted work,
- Lost time,
- Loss of consciousness,
- Medical attention beyond first aid,
- Death, or
- Any other significant work-related injury or illness diagnosed by a physician or other health care professional.

RELIABILITY

CONNECTING ONTARIO TO WHAT MATTERS

The people of Ontario depend on Hydro One as stewards of Ontario's electricity system to deliver safe and reliable electricity to power their lives. Our employees are committed to providing this level of service.

In 2014, Hydro One invested more than $224 million in Ontario's transmission system to increase electricity reliability in Toronto and the Greater Toronto Area.



CLARINGTON TRANSFORMER STATION

Hydro One received the final Environmental Assessment approval in 2014 for the Clarington Transformer Station (TS) project. Clarington TS will enable future electricity growth in the local area and address growing electricity demands in the east Greater Toronto Area (GTA). Once completed, the station will serve one million customers in the east GTA.

MAJOR INVESTMENTS

During 2014, we made capital investments totalling approximately $1.5 billion to improve our transmission and distribution systems' reliability and performance, address our aging power system infrastructure, facilitate new generation, and improve service to our customers throughout Ontario.

Our total capital investments included transmission system investments of more than $224 million to increase electricity reliability and support the energy needs in the GTA. Given the aging of our infrastructure, our ongoing investment plans are designed to reliably power our economy and to support the innovation that can be expected over the next decade.

Our major 2014 GTA investments include:

Main Transmission Station, Toronto	$9.1 million
Toronto Lakeshore Infrastructure Renewal	$53 million
Bridgman Transmission Station, Toronto	$12.3 million
Leaside Transmission Station, Toronto	$7.2 million
Basin Transmission Station, Toronto	$7 million
Claireville Transmission Station, Woodbridge	$5.5 million
Cooksville Transmission Station, Mississauga	$32.1 million
Manby Transmission Station, Toronto	$5.8 million
Gerrard Transmission Station, Toronto	$10 million
Trafalgar Transmission Station, Oakville	$15 million

ORLÉANS OPERATIONS CENTRE

In accordance with our commitment to improve reliability for our customers, in January we opened the permanently located Orléans Operations Centre, outside of Ottawa. The centre will benefit Orléans, Navan, Rockland and surrounding areas and serve roughly 39,000 customers. The centre is part of a $33.4 million investment in a new transmission line to meet growing electricity needs in the area.

WOOD POLES REPLACEMENT

Throughout 2014, Hydro One continued its wood pole replacement program – replacing 11,000 wood poles across Ontario. This proactive program targets poles more than 60 years old across our 122,000-kilometre system. With 1.6 million wood poles in our distribution system, more than 340,000 will need replacing in the next 10 years. The $82 million investment is part of an ongoing effort to make notable upgrades to system reliability and maintain public safety.

11,000

wood poles replaced in 2014

ACQUISITION OF NORFOLK POWER

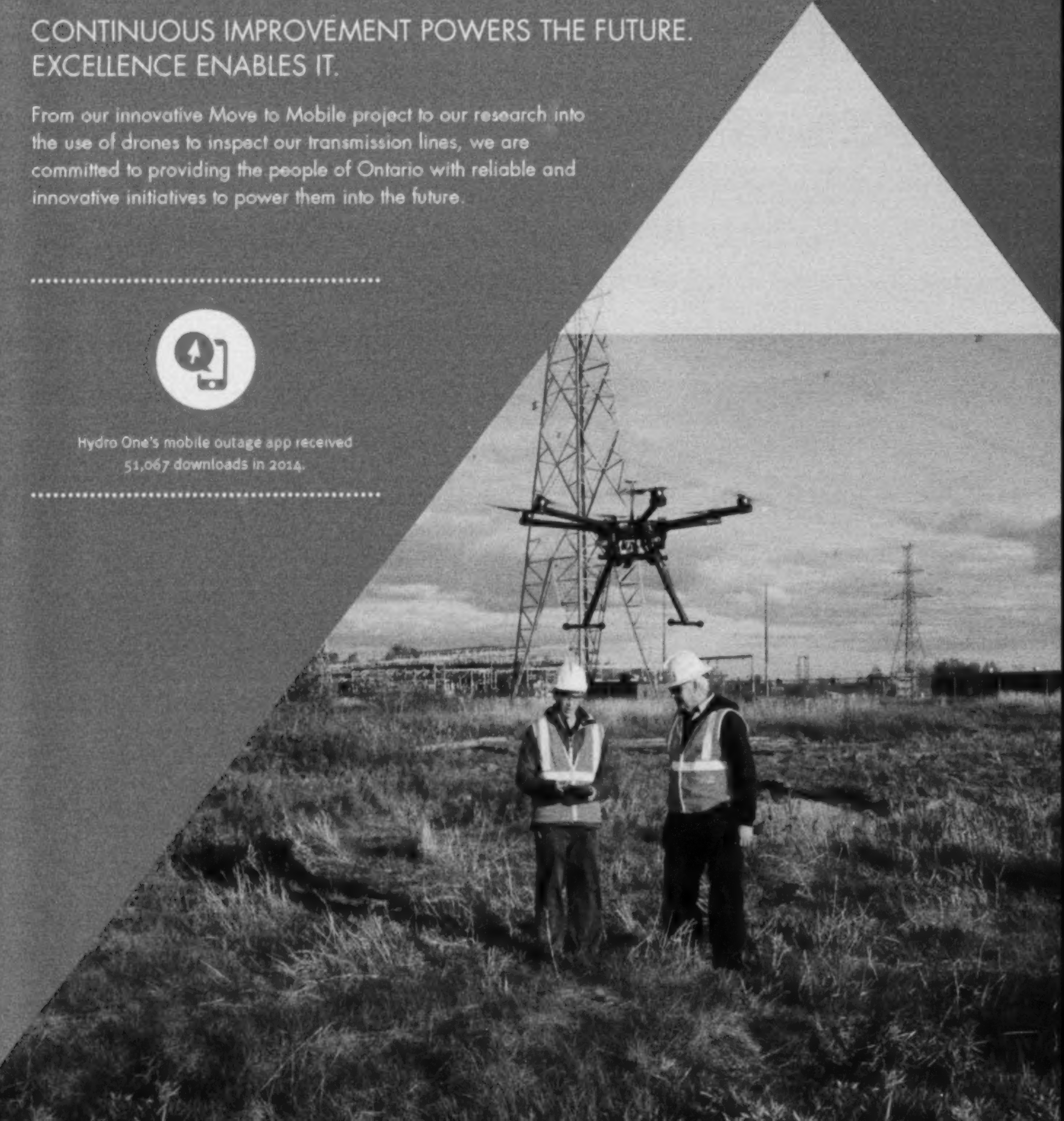
In 2014, we completed the acquisition of Norfolk Power Inc., a local distribution and telecom company in southwestern Ontario. Hydro One also reached an agreement to acquire Woodstock Hydro Holdings Inc., which is pending Ontario Energy Board approval.

EXECUTION EXCELLENCE

CONTINUOUS IMPROVEMENT POWERS THE FUTURE. EXCELLENCE ENABLES IT.

From our innovative Move to Mobile project to our research into the use of drones to inspect our transmission lines, we are committed to providing the people of Ontario with reliable and innovative initiatives to power them into the future.

Hydro One's mobile outage app received 51,067 downloads in 2014.



B2M LP WITH THE SAUGEEN OJIBWAY NATION

A first in Canada, Hydro One partnered with the Saugeen Ojibway Nation (SON) to create a limited partnership (B2M LP) to own the Bruce to Milton transmission line – a double-circuit, 500 kV line between the Bruce Nuclear Generating Station in Kincardine and our Milton Switching Station. The line – completed in 2012 – has the capacity to transmit 3,000 MW of clean, renewable energy. The SON owns a 34 per cent interest in B2M LP while Hydro One is the majority unitholder. Operations for B2M LP commenced in December 2014.

MOVE TO MOBILE PROJECT

Hydro One's Move to Mobile project is the first step in a multi-year program to enhance our existing work processes and planning by introducing industry-leading mobile capabilities. The program launched in August and will equip our workforce with a new mobility solution to perform daily tasks wherever they are in the province.

LAMBTON TO LONGWOOD CONNECTION

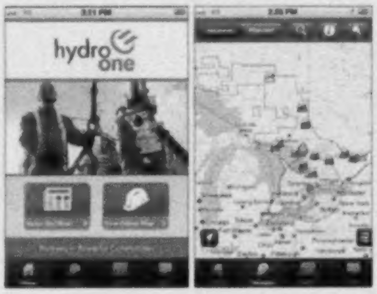
In September, we completed a $24 million upgrade to a transmission circuit between Lambton Transmission Station and Longwood Transmission Station in southwestern Ontario. The investment refurbished 36 tower foundations, replaced the circuit with a higher capacity wire and replaced insulators along the line – allowing for approximately 500 MW of renewable generation to be connected. This project used the Aluminum Conductor Steel Supported conductor for the first time in our Company's transmission system. This lightweight wire increases the line's current carrying capabilities without the need to rebuild existing towers.

DRONE TESTING

In the fall, Hydro One acquired two drones. A first for the Company, the drones will be housed at Hydro One's Kleinburg Training Centre and will be used primarily for training purposes. Work to use the drones to test our transmission lines is underway.

MOBILE APP

The Company's mobile outage app received 51,067 downloads in 2014, totalling more than 230,000 downloads since it launched in May 2012. The app connects our customers with our interactive outage mapping system, allowing them to receive detailed and updated power outage information from anywhere in our service area.



SENIOR MANAGEMENT

Carmine Marcello
President and
Chief Executive Officer,
Hydro One Inc.

Joe Agostino
Senior Vice President
and General Counsel

Laura Cooke
Senior Vice President
Customer and
Corporate Relations

John Fraser
Senior Vice President
Internal Audit

Judy McKellar
Senior Vice President
People and Culture/
Health, Safety and
Environment

Colin Penny
Senior Vice President
Technology and
Chief Information Officer

Gary Schneider
Vice President
Shared Services

Ali Suleman
Chief Financial Officer
(Acting)

Sandy Struthers
Chief Operating Officer
and Executive Vice
President Strategic
Planning

MANAGEMENT'S DISCUSSION AND ANALYSIS

For the years ended December 31, 2014 and 2013

The following Management's Discussion and Analysis (MD&A) of the financial condition and results of operations should be read together with the consolidated financial statements and accompanying notes (the Consolidated Financial Statements) of Hydro One Inc. (Hydro One or the Company) for the year ended December 31, 2014. The Consolidated Financial Statements are presented in Canadian dollars and have been prepared in accordance with United States (US) Generally Accepted Accounting Principles (GAAP). All financial information in this MD&A is presented in Canadian dollars, unless otherwise indicated.

The Company has prepared this MD&A in accordance with National Instrument 51-102 – Continuous Disclosure Obligations of the Canadian Securities Administrators. Under the US/Canada Multijurisdictional Disclosure System, the Company is permitted to prepare this MD&A in accordance with the disclosure requirements of Canada, which are different from those of the US. This MD&A provides information for the year ended December 31, 2014, based on information available to management as of February 11, 2015.

EXECUTIVE SUMMARY

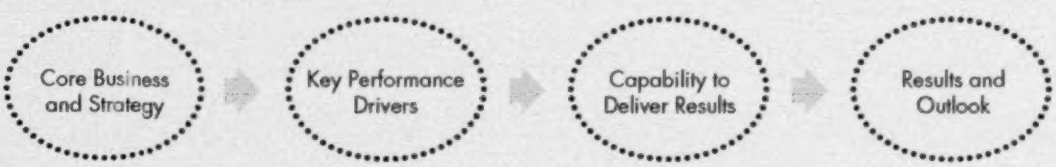
We are wholly owned by the Province of Ontario (Province or Shareholder), and our Transmission and Distribution Businesses are regulated by the Ontario Energy Board (OEB).

During 2014, we continued to focus tremendous effort on customer service and on forming a stronger relationship between our customers' satisfaction with our service and their perceptions of our company. The expectation is that in doing so, we will emerge from the challenges of this year with a renewed, transparent and consistent experience for all our customers by creating new customer tools, products, and processes and by establishing new standards for customer service. We have implemented a strong governance system that will ensure we are monitoring and measuring key performance indicators to support and advance our values with respect to being a customer caring company. We have achieved a number of targets with respect to call centre performance and billing issues to stabilize customer operations following the implementation of our new billing system, and we will continue to strive for stronger performance and an ever-improving experience for our customers.

To further improve our customer service performance culture, we have recently announced two new initiatives – a third party expert Customer Service Advisory Panel and our draft Customer Commitments. Our Customer Commitments will form the basis of our promises to our customers, and the Customer Service Advisory Panel will provide advice and hold us accountable to the promises we make to our customers. Once our Customer Commitments are finalized with input received from our customers, our employees and our Customer Service Advisory Panel, we will develop a public scorecard and will report on our performance as a transparent, accountable and customer focused organization.

Our mission and vision reflects the unique role we play in the economy of the Province and as a provider of critical infrastructure to all our customers. We strive to be an innovative and trusted company, delivering electricity safely, reliably and efficiently to create value for our customers. We operate as a commercial enterprise with an independent Board of Directors. Our strategic plan is driven by our values: health and safety; excellence; stewardship; and innovation. Safety is of utmost importance to us because we work in an environment that can be hazardous. We take our responsibility as stewards of critical provincial assets seriously. We demonstrate sound stewardship by managing our assets in a manner that is commercial, transparent and which values our customers. We strive for excellence by being trained, prepared and equipped to deliver high-quality service. We value innovation because it allows us to increase our productivity and develop enhanced methods to meet the needs of our customers.

We manage our business using the following framework:



Core Business and Strategy

Our corporate strategy is based on our mission and vision and our values. Our strategic objectives, which are discussed in the section "Overview – Our Strategy," encompass the core values that drive our business. Our strategy touches every part of our core business: health and safety; our customers; innovation; the reliability and efficiency of our systems; the environment; our workforce; Shareholder value; and productivity.

Key Performance Drivers

Performance drivers have been identified that relate to achieving our company's strategic objectives. We establish specific performance targets for each driver aimed at measuring the achievement of our strategic objectives over time. For example, we track the duration of unplanned customer interruptions per delivery point as an indication of our commitment to provide a reliable transmission system for our customers. We measure transmission and distribution unit costs as an indication of our commitment to increasing productivity. These and other key performance drivers are included in the discussion of our performance measures in the section "Overview – Performance Measures and Targets."

Capability to Deliver Results

We continue to use a balanced scorecard approach as we strive to manage our performance and deliver results each and every year. In 2014, we set 14 performance measure targets and we met or exceeded eight of them. We exceeded our targets for an injury-free workplace, timely and efficient connection of new customers, the ability to provide timely and accurate bills to customers, our Transmission Business cost-effectiveness, net income after tax, and our transmission and distribution in-service capital. Our targets, and our 2014 performance relating to these targets, are discussed in the section "Overview – Performance Measures and Targets." Our ability to deliver results in each of our strategic areas is limited by risks inherent in our regulatory environment, our business, our workforce, and in the economic environment. These risks, as well as our strategies to mitigate them, are discussed in the section "Risk Management and Risk Factors."

Results and Outlook

Consolidated Statements of Operations and Comprehensive Income

Year ended December 31 *(millions of Canadian dollars, except per share amounts)*	**2014**	2013	2012
Total revenue	**6,548**	6,074	5,728
Net income attributable to the Shareholder of Hydro One	**749**	803	745
Basic and fully diluted earnings per common share *(dollars)*	**7,319**	7,850	7,280
Cash dividends per common share *(dollars)*	**2,696**	2,000	3,523
Cash dividends per preferred share *(dollars)*	**1.375**	1.375	1.375

Consolidated Balance Sheets

December 31 (millions of Canadian dollars)	**2014**	2013	2012
Total assets	**22,550**	21,625	20,811
Total long-term debt	**8,925**	9,057	8,479
Preferred shares	**323**	323	323
Net assets	**7,947**	7,415	6,830

During 2014, we earned net income of $749 million and revenues of $6,548 million. We made capital investments totalling $1,530 million to improve our transmission and distribution systems' reliability and performance, address our aging power system infrastructure, facilitate new generation, and improve service to our customers. A full discussion of our results of operations, financing activities, and capital investments can be found in the sections "Annual Results of Operations" and "Liquidity and Capital Resources."

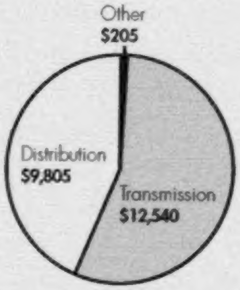
In August 2014, we completed the acquisition of Norfolk Power Inc. (Norfolk Power), an electricity distribution and telecom company located in southwestern Ontario. Hydro One has been a proud electricity distributor in Norfolk County for decades, serving approximately 14,000 Norfolk County customers. The acquisition of Norfolk Power enables our company to extend our service to the entire Norfolk County and a further 18,000 distribution customers. We are committed to delivering cost-effective service for Norfolk Power's customers and we remain focused on prudent management, efficient operations and improving the customer experience for everyone we serve. In 2014, we also signed agreements to purchase two more local distribution companies (LDCs): Woodstock Hydro Holdings Inc. (Woodstock Hydro) and Haldimand County Utilities Inc. (Haldimand Hydro). A full discussion of the Norfolk Power, Woodstock Hydro and Haldimand Hydro acquisitions can be found in the section "New Developments in 2014 – Business Combinations."

In addition, we have completed a partnership transaction with the Saugeen Ojibway Nation (SON), where the SON has acquired a noncontrolling equity interest in our new limited partnership, B2M Limited Partnership (B2M LP). A full discussion of this transaction can be found in the section "New Developments in 2014 – Business Combinations."

OVERVIEW

We are the largest electricity transmission and distribution company in Ontario. We own and operate substantially all of Ontario's electricity transmission system, accounting for approximately 97% of Ontario's transmission capacity based on revenue approved by the OEB. Based on assets, our transmission system is one of the largest in North America. Our consolidated distribution system is the largest in Ontario and spans roughly 75% of the province.

Total Assets
December 31, 2014
(millions of dollars)



Our Businesses

Our company has three reportable segments:

- Our Transmission Business, which comprises the core business of providing electricity transportation and connection services, is responsible for transmitting electricity throughout the Ontario electricity grid;
- Our Distribution Business, which comprises the core business of delivering and selling electricity to customers; and
- Other Business, which includes certain corporate activities and the operations of our telecommunications business.

Transmission Business

	2014	2013
Electricity transmitted *(TWh)*[1]	**139.8**	140.7
Ontario 20-minute system peak demand *(MW)*[1]	**23,040**	24,957
Ontario 60-minute system peak demand *(MW)*[1]	**22,774**	24,927
Total transmission lines spanning the province *(circuit-kilometres)*	**29,344**	29,344
Transmission stations *(#)*	**290**	285
Transmission transformers *(#)*	**1,471**	1,416
Transmission customers *(approximate #)*	**5,000,000**	5,000,000

[1] System-related statistics include preliminary figures for December.
TWh means terawatt-hours
MW means megawatts

Our transmission system totals approximately 29,000 circuit-kilometres of high-voltage lines whose major components consist of cables, conductors, wood or steel support structures, foundations, insulators, connecting hardware and grounding systems. We also own 290 transmission stations and over 1,400 transmission transformers. Our transmission system operates at 500 kV, 230 kV and 115 kV over relatively long distances and transmits electricity from hydroelectric, wind, solar, nuclear and coal-burning generators to customers consisting of 46 LDCs, our own distribution businesses, and 90 transmission-connected companies. It is also linked to five adjoining jurisdictions through 26 interconnections, through which we can accommodate electricity imports of up to 6,963 MW, and electricity exports of up to 6,295 MW. During 2014, our transmission system transported approximately 139.8 TWh of energy throughout Ontario.

Our Transmission Business includes the transmission businesses of our subsidiary Hydro One Networks Inc. (Hydro One Networks) as well as B2M LP. We own and operate substantially all of Ontario's electricity transmission system, and serve, directly or indirectly, approximately five million customers. Our transmission system forms an integrated transmission grid that is monitored, controlled and managed centrally from our Ontario Grid Control Centre.

In 2014, we earned total transmission revenues of $1,588 million, representing approximately 24% of our total 2014 revenues. At December 31, 2014, our Transmission Business assets were $12,540 million, representing approximately 56% of our total assets.

Distribution Business

	2014	2013
Electricity distributed to Hydro One customers *(TWh)*[1]	**29.8**	29.8
Electricity distributed through Hydro One lines *(TWh)*[1,2]	**42.4**	42.5
Total distribution lines spanning the province *(circuit-kilometres)*	**123,657**	122,853
Distribution wood poles *(approximate #)*	**1,551,000**	1,550,000
Distribution and regulating stations *(#)*	**1,026**	1,017
Distribution customers *(#)*	**1,439,321**	1,420,379

[1] System-related statistics include preliminary figures for December.

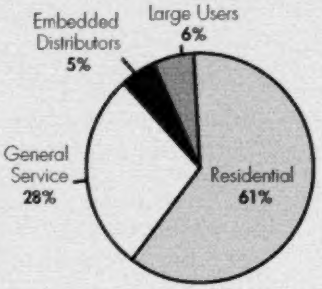
[2] Units distributed through Hydro One lines represent total distribution system requirements and include electricity distributed to consumers who purchased power directly from the IESO.

Our distribution system totals over 123,000 circuit-kilometres of distribution lines, and we own over 1,000 distribution and regulating stations and over 1.5 million distribution wood poles. Our distribution system distributes electricity from our transmission system and from more than 14,200 small generators to approximately 1.4 million of our rural and urban customers within Ontario. During 2014, approximately 42.4 TWh of electricity was distributed through our distribution system, including 29.8 TWh of electricity delivered to Hydro One customers.

Our consolidated Distribution Business includes the distribution businesses of our subsidiary Hydro One Networks and the newly acquired Norfolk Power, as well as our subsidiaries Hydro One Brampton Networks Inc. (Hydro One Brampton Networks), and Hydro One Remote Communities Inc. (Hydro One Remote Communities).

- Hydro One Networks' distribution business operates a low-voltage electrical distribution network that distributes electricity to customers, including 23 LDCs not directly connected to our transmission system, 33 LDCs connected to our transmission system, 31 customers with loads exceeding 5 MW, and approximately 1.3 million rural and urban customers.
- Hydro One Brampton Networks operates the electricity distribution system and facilities within the City of Brampton, Ontario, serving approximately 150,000 urban retail customers.
- Hydro One Remote Communities operates 19 small, regulated generation and distribution systems in 21 remote communities across northern Ontario that are not connected to Ontario's electricity grid, serving approximately 3,500 customers.

2014 Distribution Revenues



In 2014, we earned total distribution revenues of $4,903 million, including cost of purchased power of $3,419 million, representing approximately 75% of our total 2014 revenues. At December 31, 2014, our Distribution Business assets were $9,805 million, representing approximately 43% of our total assets.

Other Business

Our Other Business segment includes the operations of our subsidiary, Hydro One Telecom Inc. (Hydro One Telecom), which operates a fibre optic communications network spanning over 6,000 kilometres. Hydro One Telecom provides dark fibre and lit fibre optic capacity to telecommunications carriers and commercial customers with broadband network requirements, including a dedicated optical network providing secure, high-capacity connectivity across numerous health care locations in Ontario. Hydro One Telecom also provides telecommunication systems management and related functions which are required for our transmission and distribution businesses, including corporate data and voice networks and smart meter operations.

In 2014, our Other Business segment contributed revenues of $57 million, representing approximately 1% of our total 2014 revenues. At December 31, 2014, our Other Business segment assets were $205 million, representing approximately 1% of our total assets.

Our Strategy

Our corporate strategy builds on our strong commitment to the Province and is shaped by our values. It lays out a set of objectives to position our company to achieve our mission and vision, which is to be an innovative and trusted company delivering electricity safely, reliably and efficiently to create value for our customers. Our values represent our core beliefs.

- ***Health and safety:*** Nothing is more important than the health and safety of our employees, those who work on our property, and the public.
- ***Excellence:*** We achieve excellence through continuous training, ensuring we are prepared and equipped to deliver high-quality and affordable service, with integrity.
- ***Stewardship:*** We invest in our assets and people to build a safe, environmentally sustainable electricity network in a commercial manner.
- ***Innovation:*** We innovate through new processes, people and technology to allow us to find better ways to meet the needs of our customers.

We have eight strategic objectives that are inextricably linked. They drive the fulfillment of our mission and vision and ensure we remain focused on achieving our corporate goal of providing safe, reliable and affordable service to our customers, today and tomorrow, while increasing enterprise value for our Shareholder.

- ***Creating an injury-free workplace and maintaining public safety.*** Health and safety must be integrated into all that we do as we continue to reinforce that nothing is more important than the health and safety of our employees. We will continue to create a passion for preventing injury, staying safe and keeping each other safe. We will invest in building a culture of accountability to continue our drive to zero injuries in the workplace. In addition, we will continue to strengthen our already strong safety culture through our Journey to Zero initiative and our successful certification to the Occupational Health and Safety Assessment Series (OHSAS) 18001 standard.
- ***Satisfying our customers.*** We exist to serve our customers, and serving our customers means reducing costs, improving customer service and meeting their expectations regarding reliable power supply. We will continue to focus our efforts to improve our relationship with customers and to improve our customers' satisfaction with us. We will meet our commitments, make customers our focus in all planning discussions, communicate effectively, coordinate across our company, and maximize opportunities to improve our corporate image and every customer interaction. We will develop and deliver targeted customer segment strategies, products and delivery channels that will respond to their unique needs.
- ***Continuous innovation.*** Innovation represents one of our values and is critical to achieving our mission and vision. We have been using innovation and technology to build the foundation of our company as the utility of the future. Over the next two decades, we will continue to build on that foundation to improve the reliability and efficiency of our transmission and distribution systems and provide our customers with more capability to manage their power costs. The development of the Advanced Distribution System (ADS) is a key element in our investment in innovation, as are the investments we have made, through our Cornerstone project, in next-generation business tools to enable us to implement leading industry practices and increase productivity.

- ***Building and maintaining reliable, affordable transmission and distribution systems.*** Our transmission strategy is to provide a robust and reliable provincial grid that accommodates Ontario's emerging generation profile, manages an aging asset base and meets demand requirements through prudent expansion and effective maintenance. Our distribution strategy is focused on continuing to meet the challenge of providing reliable, affordable service to our customers in a wide range of geographical regions and climate zones; incorporating ADS technology to provide greater visibility; and increased control and improved customer service. We will meet customer expectations regarding reliability, in part through our investment planning process, which starts with the identification of asset and customer needs.
- ***Protecting and sustaining the environment for future generations.*** Consistent with our value of stewardship, we play a central role in reducing Ontario's carbon footprint through the delivery of clean and renewable energy and through measures that allow our customers to manage and reduce their energy use.
- ***Championing people and culture.*** We believe our primary strength is the capability of our people. In order to sustain this advantage, we will continue to address the issues of corporate culture, labour demographics, diversity, development of critical core competencies, and skill and knowledge retention. We will continue to develop a culture of accountability and trust as a key component to fostering employee engagement. Our labour strategy is to consolidate and clarify our collective agreements, increase flexibility and reduce costs, and maintain a progressive relationship with our unions.
- ***Maintaining a commercial culture that increases value for our Shareholder.*** For the delivery component of a customer bill, we are committed to maintaining total annual bill impacts for an average residential customer at or below the rate of inflation, and delivering income and dividends to our Shareholder. We will pursue growth opportunities through LDC consolidation to increase the enterprise value of our company by leveraging our existing assets, technologies, capabilities, unparalleled experience in LDC acquisitions, and our distribution and transmission footprint.
- ***Achieving productivity improvements and cost-effectiveness.*** To achieve our mission and vision, we must constantly strive for productivity through efficiency and effective management of costs. Productivity is key to meeting our other strategic objectives and, in particular, to achieving value for our customers and our Shareholder.

Performance Measures and Targets

We target and measure our performance by using a balanced scorecard approach. Key performance drivers are closely monitored throughout the year to ensure that we maintain a focus on our strategic objectives and take mitigating actions as required. In 2014, we met or exceeded eight of 14 performance measure targets. Overall, we are making progress towards achieving many of our strategic goals.

Injury-free Workplace

The safety of our employees is paramount. For 2014, our company used the measure of all work-related injuries or illnesses as the performance measure for this strategic objective. A "recordable" injury/illness is one of the following: medical attention (treatment beyond first aid); modified work (restricted duties); lost time; or death. For 2014, our Board of Directors set the target at 1.9 recordable injuries per 200,000 hours worked for this measure. We exceeded this target.

Satisfying our Customers

In 2014, we approached the objective of customer satisfaction by addressing five measures related to improving customer relations. These measures relate to transmission and distribution customer satisfaction, and connection of new services, as well as estimated bills and no bill volume, as part of our customer service recovery project. Our customer service recovery project was a result of billing issues our company encountered due to the implementation in May 2013 of our new Customer Information System (CIS).

- ***Customer Satisfaction – Transmission***
  This measure is to determine the degree to which our transmission customers are satisfied with the service they receive from our company. It is based on survey results of customer surveys conducted on our company's behalf by independent third parties. The survey is given to three major groups of transmission customers. In 2014, we targeted a transmission customer satisfaction rate of 84%. We did not meet this target.

- ***Customer Satisfaction – Distribution***
  Similar to the transmission customers, we survey our distribution customers to assess the degree to which they are satisfied with the service they receive from our company. The results arise from surveys conducted on our company's behalf by independent third parties. This measure reflects the overall satisfaction levels of three major distribution customer segments, based on transaction satisfaction levels, annual satisfaction surveys and the meeting of OEB milestones, respectively, for the three segments. For 2014, our company set a target for distribution customer satisfaction at 87%, and did well on the transactional elements, but did not meet this target on an overall basis.

- ***Connection of New Customers***
  This measure relates to distribution low-voltage connections that is reported annually to the OEB. It addresses our customers' needs for a specific and timely connection date and assesses our efficiency in connecting new customers. It measures the percentage of connections for a requested new service (< 750 volts). The connection must be completed within five business days from the day on which all applicable service conditions are satisfied, or at a later date agreed upon by the customer and our company. We set a 2014 target of 90%, which we exceeded.

- ***Unscheduled Estimated Bills***
  With respect to this measure, we seek to track our company's ability to provide accurate bills to our customers. We track the percentage of total customers that have received unscheduled estimates in any billing period. Our company established a target of 1.8% of all bills for this measure. We exceeded the target.

- ***No Bill Volume***
  No bill volume is a customer service measure related to our company's ability to provide timely bills to our customers. This measure tracks the number of customers who have not received a bill in three consecutive billing periods. Our expectation was to reach a volume of 8,000 no-bill customers by September 2014, and sustain this level beyond that date. We exceeded this target.

Continuous Improvement and Cost-effectiveness

As part of our strategic objectives to increase productivity through efficiency improvements and effective management of costs, our company measures transmission unit cost and distribution unit cost and sets targets for those costs. Regarding the maintenance and reliability of the transmission and distribution systems, we continue to build and retain public confidence and trust in our company's operations, as stewards of Ontario's electricity grid. In 2014, we continued our focus on this strategic priority by investing in the key assets of the electricity delivery system and by operating the existing system for customers in a safe, reliable and efficient fashion. Our company is conscious that commercial customers of all sizes require reliable service to allow them to deliver their products and services and that customers' expectations are for a reasonably limited duration when interruptions occur. Transmission and distribution reliability is measured through the duration of customer interruptions.

- ***Transmission Unit Costs***
  For 2014, the transmission unit cost measure shows the Transmission Business cost-effectiveness by comparing the ratio of operation, maintenance and administration spending to gross fixed asset costs, using benchmarking initiatives. Our company set a target of 2.9% for 2014, and exceeded the target.

- ***Distribution Unit Costs***
  Similar to transmission unit cost, the distribution unit cost measure demonstrates the distribution cost-effectiveness by comparing the ratio of operation, maintenance and administration spending to gross fixed asset costs, using benchmarking initiatives. For 2014, our company set a target of 5.7%, but did not meet this target.

- ***Customer Interruption Duration – Transmission***
  This measure monitors the reliability of the transmission system by tracking the average length of unplanned interruptions (in minutes) to multiple-circuit supplied delivery points. Our company has set a target of 8.9 minutes per delivery point for 2014. During 2014, our company was aware that we would miss the target, which was not indicative of degrading reliability, but rather a result of refurbishing aging assets. In doing so, this resulted in occasions where load with a multiple-circuit supply was placed on single supply to accommodate the work program. This exposed the system to interruptions if there was a loss of the single supply. Our company determined that it was important to continue with the maintenance program even if this would result in missing the target. Our company, in fact, did not meet this target.

- ***Customer Interruption Duration – Distribution***
  This measure is an indicator of the distribution system reliability that expresses the average length of outages in hours that a customer can expect to experience in the year. This measure excludes *force majeure* events and loss of supply events (events caused by the transmission system or other distributors). Our company set a target of 6.7 hours per customer for this measure. In 2014, there were numerous storm events which were not considered *force majeure* events and comparatively more equipment outages that resulted in higher than normal customer interruptions. In the circumstances, we did not meet this target.

Maintaining a Commercial Culture

- ***Net Income***
  Achievement of strong financial performance is measured by a performance measure of targeted level of net income after tax. Our target was $668 million net income after tax for 2014, and we exceeded our target.
- ***Customer Service Recovery Cost***
  As a result of billing issues that arose from the implementation of our new CIS in 2013, the effects of which became acute in early 2014, our company established the customer service recovery project to dedicate staff to resolve outstanding and any new billing issues and stabilize the billing system. We anticipated, and fixed as a target, costs of $48 million (including revenue impacts) for this project. The project was completed in 2014 and the CIS is now in sustainment mode. As the costs of the customer service recovery project exceeded the target, our company did not meet this anticipated target.
- ***In-Service Capital – Transmission***
  This new measure for 2014 evaluates how our company is meeting the OEB targets for in-service capital. For our Transmission Business, the 2014 target of 85% of in-service capital to our business plan is based on historical performance, our increasing capital work program, and the additional variability caused by external commitments and required approvals. Our 2014 result shows that our company exceeded the target.
- ***In-Service Capital – Distribution***
  For our Distribution Business, our company set the 2014 target of 87% of in-service capital to our business plan based on historical performance, with adjustments to reflect that our Distribution Business has more storm-related capital spending than our Transmission Business, as well as the performance of our smart meter and distributed generation capital work programs. Our 2014 result was better than the target.

REGULATION

Our Transmission and Distribution Businesses are primarily regulated by the OEB and the National Energy Board (NEB).

Provincial Framework

The *Electricity Act, 1998*, and the *OEB Act* primarily establish the broad legislative framework for Ontario's electricity market. The *Electricity Act, 1998*, sets out the fundamental principles of Ontario's electricity industry, enabling open and nondiscriminatory access to transmission and distribution systems. The *OEB Act* provides the OEB with the jurisdiction and mandate to regulate Ontario's electricity market. The OEB provides a framework for the review of electrical utilities' distribution and transmission revenue requirements so that rates may be established based on historical average or forecasted needs.

The OEB approves both the revenue requirements of and the rates charged by our regulated businesses. The rates are designed to permit our businesses to recover the allowed costs and to earn a formula-based annual rate of return on our common equity by applying a specified equity risk premium to forecasted interest rates on long-term bonds. In addition, the OEB approves rate riders to allow for the recovery or disposition of specific regulatory accounts over specified timeframes.

The OEB approved the use of US GAAP for rate setting and regulatory accounting and reporting by Hydro One Networks' Transmission and Distribution Businesses, as well as by Hydro One Remote Communities, beginning with the year 2012. Up to the year ended December 31, 2014, Hydro One Brampton Networks used Canadian GAAP (Part V) for its distribution rate-setting purposes, and has transitioned to International Financial Reporting Standards (IFRS) beginning on January 1, 2015.

Renewed Regulatory Framework

In December 2010, the OEB initiated a coordinated consultation process for the development of a Renewed Regulatory Framework for Electricity (RRFE). In October 2012, the OEB issued its report *A Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach*. The report identified three rate-setting models available to provide choices suitable for distributors having varying capital requirements: a fourth-generation Incentive Regulation Mechanism (IRM); a custom rate setting; and an Annual Incentive Rate-setting Index method. The report also provided information on performance measurement, continuous improvement and implementation of the new framework.

In late 2013, the OEB issued its *Report of the Board on Rate-Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors*. This report sets out the OEB's policies and approaches to the rate adjustment parameters for incentive rate setting for electricity distributors and the benchmarking of electricity distributor total cost performance. It also includes the OEB's determination on rate adjustment parameter values for 2014 incentive rate setting, which were used to adjust Hydro One Networks' 2014 distribution rates.

Federal Framework

While most electricity power lines and facilities in Canada fall within provincial jurisdiction, the NEB has jurisdiction over the construction and operation of international power lines (IPLs). Hydro One Networks owns and operates IPLs with New York, Michigan and Minnesota, and is subject to several NEB-issued certificates and permits. According to the *NEB Act*, any modifications to an IPL require NEB approval.

In 2012, the NEB issued a general order and five amending orders for mandatory electricity reliability standards for certain IPLs in Canada. The orders (i) require Hydro One Networks, as the owner of such lines, to comply with specified North American Electric Reliability Corporation (NERC) and Northeast Power Coordinating Council Inc. (NPCC) reliability standards, (ii) mandate certain reporting requirements, and (iii) contain provisions for IPL owners to seek exemptions. In March 2013, Hydro One Networks submitted to the NEB a declaration of compliance and a request for indefinite exemptions from a list of standards that do not apply to Hydro One Networks or to the IPLs it owns. On November 13, 2013, the NEB granted Hydro One Networks' exemption requests, with some minor exceptions. Hydro One Networks maintains compliance with all applicable NEB orders and seeks approval for all appropriate exemptions, as required.

NERC Critical Infrastructure Protection (Cyber Security) standards are designed to ensure that utilities and other users, owners, and operators of the bulk power system in North America have appropriate procedures in place to protect critical infrastructure from cyber attack. As a result, our physical, electronic and information security processes have been upgraded to meet more stringent security requirements in order to meet NERC's requirements. The NERC Cyber Security standards were updated and revised in 2013, resulting in additional work, effort and associated costs for our company. We anticipate these costs will be spread over a number of years, and expect that they will be recovered in future rates.

Regulatory Proceedings

The following table summarizes our company's recent major regulatory proceedings:

Application	Year(s)	Type	Date Filed	Current Status
Electricity Rates – Transmission Rate Applications				
Hydro One Networks	2013–2014	Cost-of-service	May 28, 2012	OEB decision received on January 9, 2014[1]
Hydro One Networks	2015–2016	Cost-of-service	September 16, 2014	OEB decision received on December 2, 2014
B2M LP	2015	Interim	October 24, 2014	OEB decision received on December 11, 2014
Electricity Rates – Distribution Rate Applications				
Hydro One Networks	2014	IRM	April 26, 2013	OEB decision received December 5, 2013
Hydro One Networks	2015–2019	Custom	December 19, 2013	OEB decision anticipated in 2015 Q1
Hydro One Brampton Networks	2014	IRM	August 14, 2013	OEB decision received December 5, 2013
Hydro One Brampton Networks	2015	Cost-of-service	April 23, 2014	OEB decision received on January 15, 2015
Hydro One Remote Communities	2014	IRM	October 25, 2013	OEB decision received March 13, 2014
Hydro One Remote Communities	2015	IRM	September 24, 2014	OEB decision anticipated in 2015 Q1
Mergers Acquisitions Amalgamations and Divestitures (MAAD) Applications				
Norfolk Power	n/a	Acquisition	April 26, 2013	OEB decision received July 3, 2014
Woodstock Hydro	n/a	Acquisition	July 9, 2014	OEB decision anticipated in 2015
Haldimand Hydro	n/a	Acquisition	July 31, 2014	OEB decision anticipated in 2015
Leave to Construct Application				
Supply to Essex County Transmission Reinforcement Project	n/a	Section 92	January 22, 2014	OEB decision anticipated in 2015

[1] OEB Oral Decision for 2013 transmission rates was received on November 8, 2012. On December 6, 2013, we submitted a draft Rate Order for our 2014 transmission rates. On January 9, 2014, the OEB approved the draft Rate Order for 2014 transmission rates as filed.

Electricity Rates

Under the current market structure, low-volume and designated consumers pay electricity rates established through the Regulated Price Plan (RPP). The RPP regulates the commodity price of electricity only and does not affect the rates charged for transmission and distribution of electricity. The OEB sets prices for RPP customers based on both a two-tiered electricity pricing structure with seasonal consumption thresholds, and a three-tiered electricity pricing structure with Time-of-Use (TOU) thresholds. New RPP prices are computed at six-month intervals and are the result of an integrated consideration of rebasing and true-ups. The following is a summary of the two-tiered RPP and the TOU RPP prices for the reporting and comparative periods:

RPP	Tier Threshold (kWh/month)		Tier Rates (cents/kWh)	
Effective Date	**Residential**	**Non-Residential**	**Lower Tier 1**	**Upper Tier 2**
November 1, 2012	1,000	750	7.4	8.7
May 1, 2013	600	750	7.8	9.1
November 1, 2013	1,000	750	8.3	9.7
May 1, 2014	600	750	8.6	10.1
November 1, 2014	1,000	750	8.8	10.3

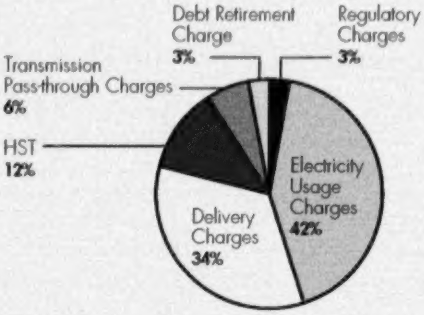
TOU RPP	**Rates (cents/kWh)**		
Effective Date	**On Peak**	**Mid Peak**	**Off Peak**
November 1, 2012	11.8	9.9	6.3
May 1, 2013	12.4	10.4	6.7
November 1, 2013	12.9	10.9	7.2
May 1, 2014	13.5	11.2	7.5
November 1, 2014	14.0	11.4	7.7

In 2010, the OEB issued its final determination to mandate TOU pricing for RPP customers. All eligible Hydro One distribution customers were migrated to TOU billing as of June 2011, except certain customers located in very rural and very sparsely populated areas. An exemption from the requirement to move these customers to TOU pricing was approved until December 31, 2014. On December 1, 2014, Hydro One filed a request with the OEB for a five-year exemption extension for 120,000 hard-to-reach customers and requested permission to migrate an additional 50,000 customers back to two-tiered RPP pricing, as it is not economically feasible to consistently provide actual readings from these meters. An OEB Hearing on this matter has commenced. The OEB issued an interim Decision granting an exemption extension until June 30, 2015 or until a final OEB Decision is issued.

Customers who are not eligible for the RPP and wholesale customers pay the market price for electricity, adjusted for the difference between market prices and prices paid to generators by the Independent Electricity System Operator (IESO) under the *Electricity Act, 1998*. The IESO is responsible for overseeing and operating the wholesale electricity market, as well as ensuring the reliability of the integrated power system.

A typical residential customer consumes 800 kWh of electricity per month. The total bill for a typical residential customer consists of the following: electricity usage charges based on RPP rates; electricity delivery charges based on OEB-approved distribution rates; transmission pass-through charges for the usage of the transmission system; regulatory charges, which include wholesale market costs and rural and remote rate protection amounts; the debt retirement charge; and the harmonized sales tax (HST).

Composition of Total Bill for Typical Residential Customer



Transmission Rates

Our transmission revenues primarily include our transmission tariff, which is based on the province-wide Uniform Transmission Rates (UTRs) approved by the OEB for all transmitters across Ontario. The OEB rate-setting process is a rigorous judicial process based on evidence, and usually legal cross-examination of witnesses who testify to the volumes of information submitted. The transmission tariff rates are set based on an approved revenue requirement that provides for cost recovery and a return on our common equity.

- **Hydro One Networks**
  In May 2012, we filed a cost-of-service rate application with the OEB for our 2013 and 2014 transmission rates. The application sought OEB approval for revenue requirement increases of approximately 0.6% in 2013 and 9.1% in 2014, or estimated increases of 0% in 2013 and 0.7% in 2014 on a typical residential customer's total bill. In November 2012, we submitted a draft Rate Order, which included revenue requirements of approximately $1,438 million and $1,528 million for 2013 and 2014, respectively. For a typical residential customer, this represents no change from the 2012 OEB-approved rate levels in 2013 and a 5.8% increase in 2014 for the transmission portion of the bill, or no change for 2013 and an increase of 0.5% for 2014 when considering total bill impact. In December 2012, the OEB approved the 2013 and 2014 transmission revenue requirements as requested. The 2013 Ontario UTRs remained unchanged at the 2012 levels.

On December 6, 2013, we submitted a draft Rate Order for our 2014 transmission rates. The 2014 revenue requirement increased to $1,535 million from the originally-approved revenue requirement of $1,528 million, primarily due to changes in the cost of capital parameters for 2014 released by the OEB in November 2013. On January 9, 2014, the OEB approved the draft Rate Order for 2014 transmission rates as filed. For a typical residential customer, this represents an increase of 6.3% in 2014 for the transmission portion of the bill, or 0.5% when considering total bill impact.

On September 16, 2014, Hydro One Networks filed its application, evidence and Settlement Agreement with the OEB in support of proposed transmission revenue requirements to be implemented on January 1, 2015 and January 1, 2016. This application is pursuant to a comprehensive Settlement Agreement between the stakeholders and Hydro One Networks. On January 8, 2015, the OEB approved the Hydro One transmission rates revenue requirement, excluding the B2M LP revenue requirement, for 2015 of $1,477 million and the 2016 revenue requirement of $1,516 million, subject to adjustments for the cost of capital parameters. For a typical residential customer, this represents increases of 0.4% in 2015 and 1.4% in 2016 for the transmission portion of the bill, or increases of 0.03% in 2015 and 0.1% in 2016 when considering total bill impact.

- **B2M LP**

  On October 24, 2014, B2M LP filed an application with the OEB for an interim transmission rate, effective January 1, 2015, seeking approval for a revenue requirement of $41 million in 2015. This rate is equal to the amount included in Hydro One Networks' transmission rates for the Bruce to Milton Line assets, resulting in no change to overall UTRs. The interim Rate Order was approved by the OEB on December 11, 2014. B2M LP was directed to file a full cost-of-service application for final 2015 transmission rates by April 1, 2015.

  A full discussion of the B2M LP transaction can be found in the section "New Developments in 2014 – Business Combinations."

Distribution Rates

Our distribution revenues primarily include our distribution tariff, which is based on OEB-approved rates, and the recovery of the cost of purchased power used by our customers. The distribution tariff rates are set based on an approved revenue requirement that provides for cost recovery and a return on our common equity.

- **Hydro One Networks**

  In June 2012, Hydro One Networks filed an IRM application with the OEB for 2013 distribution rates, to be effective January 1, 2013. In December 2012, the OEB issued a final Rate Order, which resulted in an increase in distribution rates of approximately 1.3% in 2013, or 0.4% when considering total bill impact, for a typical residential customer.

  On April 26, 2013, Hydro One Networks filed an IRM application with the OEB for 2014 distribution rates, to be effective January 1, 2014. On September 26, 2013, the OEB issued a partial Decision, approving a rate rider to recover a 2014 revenue requirement of $29 million for operation, maintenance and administration expenses and in-service capital costs of the ADS Project, which will modernize our distribution system. On December 5, 2013, the OEB issued its final Decision, which resulted in an increase of distribution rates of approximately 2.4% in 2014, or 0.85% when considering total bill impact, for a typical residential customer.

  On December 19, 2013, Hydro One Networks filed a 2015–2019 distribution custom rate application with the OEB, for rates effective January 1 of each test year. This application is a five-year custom rate application submitted under the OEB's RRFE, and has been customized to fit Hydro One Networks' specific circumstances, which necessitate significant multi-year investments. We are seeking OEB approval for distribution revenue requirements of $1,415 million for 2015, $1,523 million for 2016, $1,578 million for 2017, $1,615 million for 2018, and $1,660 million for 2019. If the application is approved as filed, the resulting change to the distribution portion of the bill for a typical residential customer will be approximately a 1.4% decrease in 2015, 3.8% increase in 2016, 2.3% increase in 2017, 1.2% increase in 2018, and 2.6% increase in 2019. When considering total bill impact, the resulting change will be approximately a 1.5% decrease in 2015, 1.3% increase in 2016, 0.8% increase in 2017, 0.4% increase in 2018, and 0.9% increase in 2019 for a typical residential customer. A technical conference, a settlement conference and an Oral Hearing took place in the third quarter of 2014. On December 18, 2014, the OEB issued a Decision and interim Rate Order approving the 2014 distribution rates as interim 2015 rates effective January 1, 2015. The OEB also approved the discontinuation of the collection of revenues for the provincially funded portion of renewable generation connection investments of approximately $20 million per year from ratepayers effective December 31, 2014. A final Decision and Order from the OEB is anticipated in the first quarter of 2015.

- **Hydro One Brampton Networks**

  In August 2012, Hydro One Brampton Networks filed an IRM application with the OEB for 2013 distribution rates, to be effective January 1, 2013. In December 2012, the OEB released a Decision that resulted in an increase in distribution rates of approximately 0.3% for 2013, or less than 0.1% on the average total bill for a typical residential customer.

  In August 2013, Hydro One Brampton Networks filed an IRM application with the OEB for 2014 distribution rates, to be effective January 1, 2014. On December 5, 2013, the OEB released a Decision that resulted in a reduction in distribution rates of approximately 2.3% for 2014, or a 0.5% reduction on the average total bill for a typical residential customer.

  On April 23, 2014, Hydro One Brampton Networks filed a cost-of-service application with the OEB for 2015 distribution rates, to be effective January 1, 2015, after being in an IRM application period for three years. The 2015 distribution rate application was seeking the approval of a revenue requirement of approximately $74 million for 2015. In its application, Hydro One Brampton Networks also requested OEB approval for retail transmission service rates and the approval of rate riders to dispose of certain deferral and variance accounts. A partial Settlement Proposal was filed with the OEB and the unsettled issues were heard by the OEB in an Oral Hearing in October 2014. On December 18, 2014, the OEB approved a revenue requirement of $72 million. The reduction of $2 million is mainly attributable to updates to the cost of capital parameters, operation, maintenance and administration, and depreciation expense. For a typical residential customer, this represents an increase of 4.5% in 2015 for the distribution portion of the bill, or 1.6% when considering total bill impact. The increase is reflective of increased rate base and higher operation, maintenance and administration costs since Hydro One Brampton Networks' last cost-of-service application in 2011. On January 15, 2015, the OEB issued its final Rate Order approving the application.

- **Hydro One Remote Communities**

  In September 2012, Hydro One Remote Communities filed a cost-of-service application with the OEB for 2013 distribution rates, seeking approval for a 2013 revenue requirement of $53 million. In August 2013, the OEB issued a final Decision approving a revenue requirement of $51 million and rate increase of approximately 3.45%, with an effective date of May 1, 2013.

  In October 2013, Hydro One Remote Communities filed an IRM application with the OEB for 2014 distribution rates, seeking approval for a rate increase of approximately 0.48%. On March 13, 2014, the OEB approved an increase of approximately 1.7% to basic rates for the distribution and generation of electricity, with an effective date of May 1, 2014. The final rate increase was adjusted by the OEB's updated rate adjustment parameters.

  On September 24, 2014, Hydro One Remote Communities filed an IRM application with the OEB for 2015 rates, seeking approval for increased base rates for the distribution and generation of electricity of 1.7% to be effective May 1, 2015. A final Decision from the OEB is anticipated in the first quarter of 2015.

Mergers Acquisitions Amalgamations and Divestitures (MAAD) Applications

Norfolk Power Acquisition

On April 26, 2013, Hydro One filed a MAAD application with the OEB for the approval of the acquisition of Norfolk Power. On July 3, 2014, the OEB issued its Decision and Order granting Hydro One leave to acquire all of the issued and outstanding common shares of Norfolk Power within 18 months from the date of this Decision and Order. In addition, among other items, the OEB's Decision and Order granted Norfolk Power Distribution Inc. (NPDI), a subsidiary of Norfolk Power, leave to transfer its distribution system to Hydro One Networks within 18 months from the date of this Decision and Order, and ordered that NPDI file with the OEB a draft Rate Order that includes a proposed Tariff of Rates and Changes reflecting the OEB's approval of a 1% reduction relative to NPDI's 2012 base electricity delivery rates. As part of the Norfolk Power acquisition agreement, Norfolk Power residential customers received a 1.4% reduction to their monthly distribution delivery rates, and general service customers received a reduction of between 1.4% and 1.6%, depending on their rate class, effective September 8, 2014. In addition, Norfolk Power customers' distribution rates will be frozen for the next five years. Once the NPDI distribution system transfer is completed, the OEB will transfer NPDI's electricity distribution licence and NPDI's Rate Order to Hydro One Networks. A full discussion of the Norfolk Power acquisition can be found in the section "New Developments in 2014 – Business Combinations."

Woodstock Hydro Acquisition

On July 9, 2014, Hydro One filed a MAAD application with the OEB for the approval of the acquisition of Woodstock Hydro, which is anticipated to be completed in 2015. A full discussion of the Woodstock Hydro acquisition can be found in the section "New Developments in 2014 – Business Combinations."

Haldimand Hydro Acquisition

On July 31, 2014, Hydro One filed a MAAD application with the OEB for the approval of the acquisition of Haldimand Hydro, which is anticipated to be completed in 2015. A full discussion of the Haldimand Hydro acquisition can be found in the section "New Developments in 2014 – Business Combinations."

Leave to Construct Application

Supply to Essex County Transmission Reinforcement Project

On January 22, 2014, Hydro One Networks submitted a Leave to Construct application to the OEB under Section 92 of the *OEB Act* to construct a new 13-kilometre 230 kV double-circuit transmission line in the Windsor-Essex region. The new transmission line will connect to a proposed transmission station in the Municipality of Leamington and an existing 230 kV transmission line between Chatham and Windsor. Further discussion of the Supply to Essex County Transmission Reinforcement Project can be found in the section "Liquidity and Capital Resources – Investing Activities – Major Transmission Projects."

Contractual Agreements, Codes and Licences

As a regulated company, we are subject to various contractual arrangements, codes and licences.

Operating Agreement with the IESO

The IESO is the system controller of Ontario's electricity system. The IESO manages the reliability of Ontario's power system, forecasts the demand and supply of electricity and co-ordinates emergency preparedness for Ontario's electricity system. The IESO also operates the wholesale electricity market, while ensuring fair competition through market surveillance.

Under the *Electricity Act, 1998*, the IESO is required to enter into agreements with transmitters, giving it the authority to direct the operations of the transmitters' systems. Our operating agreement with the IESO, which sets out the specific responsibilities of both parties relating to the provision of transmission service, extends until December 31, 2019. The distribution portion of Ontario's network is not directed by the IESO and remains subject to the operational control of LDCs in accordance with the regulatory framework.

Hydro One's Relationships with Other Market Participants

Generators, LDCs and customers directly connected to our transmission system must enter into agreements with us to ensure reliable connection service in conformity with the Transmission System Code (TSC) established by the OEB.

Some market participants, such as generators and large load customers embedded within distribution systems, are supplied from the wholesale market through lines and facilities that are defined or deemed by the OEB as "distribution" and owned by LDCs. At a minimum, under the *Electricity Act, 1998*, LDCs must provide nondiscriminatory access for eligible generators and customers to the wholesale markets administered by the IESO.

Electricity Industry Codes

The OEB has issued and revised several codes that govern the operation of OEB-licensed entities in Ontario. These codes include, but are not limited to, the Affiliate Relationships Code for Electricity Distributors and Transmitters, the Standard Supply Service Code, the TSC, the Distribution System Code (DSC), the Retail Settlement Code, the Electricity Retailer Code of Conduct, the Smart Sub-Metering Code, and the Conservation and Demand Management (CDM) Code. These codes prescribe minimum standards of conduct and standards of service for transmitters, distributors, smart sub-metering providers and/or retailers in the electricity market.

Electricity Industry Licences

Our transmission and distribution licences were issued in 2003 and 2004, respectively. The licences for all of our regulated businesses have a 20-year term and incorporate reporting and record-keeping requirements in accordance with the OEB's Electricity Reporting and Record Keeping Requirements. Further discussion of the OEB's Electricity Reporting and Record Keeping Requirements can be found in the section "Regulation – Regulatory Developments – Performance Measurement and Continuous Improvement." Our licences promote the expansion and upgrading of the transmission and distribution systems to accommodate load due to forecasted demand growth over the long term, the connection of renewable energy generation facilities, and implementation of modern technologies to improve reliability, operations and network planning.

Regulatory Developments

Long-Term Energy Plan

On December 2, 2013, the Province released its updated Long-Term Energy Plan (2013 LTEP), *Achieving Balance*, replacing the 2010 LTEP. The 2013 LTEP sets out the Province's plan of action for the energy sector, including strategies for mitigating increases in electricity rates; continued renewable energy procurement; nuclear refurbishment; enhanced regional planning with respect to energy infrastructure; transmission enhancements; encouraging Aboriginal participation in energy development, transmission and conservation projects; and the expansion of natural gas infrastructure. The plans are guided by the goal of balancing five core principles: cost-effectiveness, reliability, clean energy, community engagement, and CDM. Pursuant to the 2013 LTEP, the Province "will encourage Ontario Power Generation Inc. (OPG) and Hydro One to explore new business lines and opportunities inside and outside Ontario. These opportunities will help leverage existing areas of expertise and grow revenues for the benefit of Ontarians." We will continue to work with the Province to develop business plans and efficiency targets that will reduce costs and result in significant ratepayer savings. The 2013 LTEP encourages conservation and reinforces the policy of considering conservation first in planning processes. Under the 2013 LTEP, conservation will be used to lessen the need for new supply-and-demand response initiatives to meet peak demand requirements.

Procurement of New Generation

The Ontario Power Authority's (OPA) Feed-in Tariff (FIT) Program is designed to procure energy from a wide range of renewable energy sources, including wind, solar, photovoltaic, bio-energy, and water power up to 50 MW. The FIT program is currently divided into three streams: MicroFIT (projects up to 10 kW), Small FIT (projects between 10 kW and 500 kW), and regular FIT (projects greater than 500 kW), all of which may result in connections to our distribution system. Under the FIT program, the OPA has entered into contracts or conditional contracts with generation proponents pursuant to which the OPA will pay a fixed rate for power produced over a specified period of time. We continue to connect projects for which there are firm contracts.

On May 30, 2013, the Province announced that it would make 900 MW of new capacity available between 2013 and 2018 for the Small FIT and MicroFIT programs. The Province has set annual procurement targets, from 2014 onwards, of 150 MW for Small FIT generation and 50 MW for MicroFIT generation. The Province is working with the OPA to develop a competitive process for renewable energy generation projects above 500 kW. The new process will replace the existing large project stream of the FIT program. As at December 31, 2014, our company has connected more than 560 FIT and nearly 12,000 MicroFIT projects, enough energy to power approximately 274,000 homes. These connections represent over 1,000 MW of power.

Conservation and Demand Management

The OEB's CDM guidelines for electricity distributors provide guidance on certain provisions in the CDM Code and the type of evidence that should be filed by distributors in support of applications for OEB-approved CDM programs. The guidelines also provide details on the Lost Revenue Adjustment Mechanism (LRAM) related to CDM programs implemented under the CDM Code. LRAM is the mechanism by which LDCs are compensated for lost revenues associated with their respective load reductions resulting from CDM programs. In addition, the guidelines state that savings associated with TOU pricing are eligible to be counted towards the 2011–2014 CDM targets. The funding for the OPA-contracted Ontario-wide CDM programs is in place until December 31, 2015. This will provide an opportunity for the OPA and LDCs to work collaboratively to strengthen the current framework, and to keep customer programs in place for 2015.

On September 30, 2014, in accordance with the CDM Code, Hydro One Networks and Hydro One Brampton Networks each filed a 2013 Annual CDM Report with the OEB outlining CDM activities, energy and peak demand savings results achieved in 2013, and expectations regarding CDM targets for 2014. Hydro One Networks reported that it expected to reach 95% to 100% of its demand target and 80% of its cumulative energy target by the end of 2014. Hydro One Brampton Networks reported that it expected to reach 60% of its demand target and 100% of its cumulative energy target by the end of 2014.

In March 2014, the Minister of Energy issued parallel directives to the OEB and the OPA, respectively, regarding the new "2015–2020 Conservation Framework." The directives call for the OPA to establish a provincial target of 7 TWh of persistent energy savings to be achieved by 2020 and for all LDCs to enter into an Electricity Conservation Agreement with the OPA by December 31, 2014. Both Hydro One Networks and Hydro One Brampton Networks submitted their signed Electricity Conservation Agreements to the OPA in December 2014. Conservation opportunities will be provided to customers and available to distributors to ensure both end-user usage and utility systems are as efficient as possible.

The OPA allocated targets and budgets to LDCs on October 31, 2014. Hydro One Networks' 2015–2020 CDM savings target is 1,159 GWh, to be achieved with a budget of approximately $322 million. Hydro One Brampton Networks' 2015–2020 CDM savings target is 255.2 GWh, to be achieved with a budget of approximately $67 million. All LDCs must submit CDM Plans indicating how they will achieve their allocated targets by May 1, 2015 using either "Full Cost Recovery" or "Pay-for-Performance" funding models. All CDM programs must be cost-effective to ensure full cost recovery. LDCs may, at any point, resubmit changes to their CDM Plan for approval by the OPA.

On December 19, 2014, the OEB issued its new CDM Guidelines (2015 Guidelines). The 2015 Guidelines are consistent with the Directive the OEB received in March 2014 from the Minister of Energy requiring the OEB to take steps to promote CDM, including amendments to the licences of electricity distributors and the establishment of CDM Requirement guidelines.

Revenue Decoupling for Distributors

In November 2012, the OEB initiated a project to coordinate revenue decoupling with the new rate-setting policies proposed in the RRFE. On April 3, 2014, the OEB released a Draft Report of the Board on Rate Design for Electricity Distributors (Rate Design Report) to solicit stakeholder comments. The Rate Design Report presents three proposals to achieve revenue decoupling: (1) a single monthly charge which is the same for all consumers within the rate class; (2) a fixed monthly charge, with the size of the charge to be based on the size of the electrical connection; and (3) a fixed monthly charge where the size of the charge is based on use during peak hours. The OEB expects to issue a report in early 2015 regarding the phase-in implementation of fixed rates.

Performance Measurement and Continuous Improvement

On March 5, 2014, the OEB issued its *Report of the Board on Performance Measurement for Electricity Distributors: A Scorecard Approach* (Performance Report) under its RRFE. The Performance Report sets out the OEB's policies on the measures that will be used by the OEB to assess a distributor's effectiveness and improvement in achieving customer focus, operational effectiveness, public policy responsiveness, and financial performance to the benefit of existing and future customers, as well as the form and implementation of a performance monitoring tool – a Scorecard.

On July 15, 2014, the OEB issued a Staff Discussion Paper "Electricity Distribution System Reliability Measures and Targets" to establish specific performance targets for the existing system reliability measures, to develop customer-specific reliability measures and to address the monitoring of momentary outages.

Regional Plans

In August 2013, the OEB amended the TSC and DSC to implement a more formal and structured approach to regional planning in Ontario. The new regional planning approach consists of two main processes: Regional Infrastructure Planning (RIP) to be led by transmitters, and Integrated Regional Resource Planning (IRRP) to be led by the OPA. The RIP process focuses mainly on wires planning, both transmission and distribution, and the IRRP process focuses on resources planning (e.g. generation, CDM) and the integration of resources with wires planning. The development of regional plans will involve close coordination of the two processes and active participation by the OPA, transmitters, distributors and other applicable agencies such as the IESO.

The regional plans are intended to support investments brought forward in transmitter and distributor rate submissions and transmitter Leave to Construct applications. Regional plans are to be reviewed or developed at least every five years. The OEB expects the first cycle of regional plans for all regions in Ontario to be completed in the next three to four years. For regional planning purposes, the province has been subdivided into 21 regions. Hydro One is the lead transmitter responsible for the RIP process for 19 of the 21 regions. Planning activities are underway and the regional plans are expected to be completed between 2015 and 2017.

NEW DEVELOPMENTS IN 2014

Premier's Advisory Council on Government Assets

On April 11, 2014, the Province announced the appointment of the Premier's Advisory Council on Government Assets (Council) to provide the Province with recommendations designed to maximize the value of certain provincially owned assets, one of which being our company. The objective of the review is to advise the Province on how to best maximize value from its assets. The Council's Terms of Reference provided guidance indicating that it would give preference to continued ownership of government assets, but would consider mergers, acquisitions, divestments if there is a strong business case, and would enhance value to taxpayers of the Province.

The interim report released on November 19, 2014, noted our company's Transmission Business is a well-run entity with some opportunities to deliver savings on the operating side and on capital expenditures, and recommended that the Province maintain its ownership of our company's Transmission Business. The interim report noted that Ontario's local electricity distribution system is an unnecessarily cluttered and fragmented system with too many entities, some of which are highly inefficient, unable to adapt to the changing environment and lack capital to modernize or consolidate.

Consequently, the Council recommended that our company's Transmission and Distribution Businesses be separated, and that Hydro One Networks' distribution business and Hydro One Brampton Networks be used to spur industry consolidation. The Council also recommended that the Province reduce its equity interest in our company's Distribution Business by bringing in private sector investment.

The Province has now asked the Council to build on its work by entering phase two, which includes the Council receiving and discussing written ideas related to encouraging consolidation and to Hydro One Brampton Networks and Hydro One Networks' distribution business, and finalizing its recommendations to the Province. We understand that the Province is specifically considering the sale of Hydro One Brampton Networks, as well as the distribution business of Hydro One Networks.

Business Combinations

B2M LP

In 2012, we entered into an agreement with the Chippewas of Nawash First Nation and the Chippewas of Saugeen First Nation, collectively referred to as the SON, where a noncontrolling equity interest in B2M LP would be made available for purchase at fair value by the SON. B2M LP was formed by Hydro One in 2013 to hold most of the transmission lines and a licence to use the related land. These assets are associated with our Bruce to Milton Transmission Reinforcement Project, an electricity transmission line (Bruce to Milton Line) in southwestern Ontario, from the Bruce Power facility in Kincardine to our Milton Switching Station in the Town of Milton. Hydro One Networks will maintain and operate the Bruce to Milton Line in accordance with an operation and management services agreement. In November 2013, the OEB issued a Decision and Order granting B2M LP a transmission licence and granting Hydro One Networks leave to sell the relevant Bruce to Milton Line transmission assets to B2M LP.

On December 16, 2014, the relevant Bruce to Milton Line transmission assets totalling $526 million were transferred from Hydro One Networks to B2M LP. This was financed by 60% debt ($316 million) and 40% equity ($210 million). On December 17, 2014, the SON acquired a 34.2% equity interest in B2M LP for consideration of $72 million, representing the fair value of the equity interest acquired. B2M LP is now operational.

Details of B2M LP's transmission rate application can be found in the section "Regulation – Regulatory Proceedings – Transmission Rates."

Norfolk Power Acquisition

On August 29, 2014, our company completed the acquisition of the outstanding shares of Norfolk Power from The Corporation of Norfolk County. Norfolk Power is a holding company that owns NPDI, a local electricity distribution company, and Norfolk Energy Inc., a non-rate regulated energy services company, located in southwestern Ontario. The selection of our company as successful bidder followed a comprehensive, competitive sales process initiated by Norfolk Power.

The total purchase price for Norfolk Power, net of the long-term debt assumed and adjusted for preliminary working capital and other closing adjustments, is approximately $68 million. The determination of the fair values of assets acquired and liabilities assumed has been based upon management's estimates and certain assumptions with respect to the fair values of the assets acquired and liabilities assumed. We have also determined the preliminary purchase price adjustments based on agreed working capital and other balances at the acquisition date. The resulting preliminary goodwill of approximately $40 million arising from the Norfolk Power acquisition consists largely of the synergies and economies of scale expected from combining the operations of Hydro One and Norfolk Power. We intend to complete the determination of the final purchase price adjustments during the first half of 2015.

Norfolk Power contributed revenues of $18 million and net income of less than $1 million to our company's consolidated financial results for the year ended December 31, 2014.

Details of the Norfolk Power MAAD application can be found in the section "Regulation – Regulatory Proceedings – MAAD Applications."

Woodstock Hydro Purchase Agreement

On May 21, 2014, we reached an agreement with the City of Woodstock to acquire 100% of the common shares of Woodstock Hydro for approximately $29 million, subject to final closing adjustments. Woodstock Hydro is an urban electricity distribution company located in southwestern Ontario. The transaction is the result of extensive discussions between Hydro One and the City of Woodstock which involved consideration of economic development opportunities and other benefits resulting from the sale of Woodstock Hydro. The acquisition is pending a regulatory decision from the OEB and is anticipated to be completed in 2015.

Details of the Woodstock Hydro MAAD application can be found in the section "Regulation – Regulatory Proceedings – MAAD Applications."

Haldimand Hydro Purchase Agreement

On June 10, 2014, we reached an agreement with Haldimand County to acquire 100% of the common shares of Haldimand Hydro for approximately $65 million, subject to final closing adjustments. Haldimand Hydro is an electricity distribution and telecom company located in southwestern Ontario. The transaction is the result of extensive discussions between Hydro One and Haldimand County. The acquisition is pending a regulatory decision from the OEB and is anticipated to be completed in 2015.

Details of the Haldimand Hydro MAAD application can be found in the section "Regulation – Regulatory Proceedings – MAAD Applications."

Other

Environment Canada Regulations

In April 2014, Environment Canada issued Canada Gazette II, which included amendments to the existing polychlorinated biphenyl (PCB) regulations, including the extension of the end-of-use deadline beyond 2014 for equipment containing certain concentrations of PCBs, with an effective date of January 1, 2015. The amendments extend the end-of-use deadline for our company's PCBs in concentrations of 500 parts per million or more from December 31, 2014 to December 31, 2025. As a result of an annual review of environmental liabilities, our company recorded a revaluation adjustment in 2014 to reduce our environmental liabilities by $20 million. This adjustment included the impact of the PCB regulations amendments.

Electricity Sector Pension Plans

On August 1, 2014, a Report on the Sustainability of Electricity Sector Pension Plans (Sustainability Report) was released by Jim Leech, Special Advisor to the Minister of Finance for Ontario. As part of its fiscal 2013 budget, the Province announced its intention to establish a government-led industry Working Group (Working Group) to address pension issues associated with the single-employer pension plans at Hydro One, OPG, IESO and the Electrical Safety Authority (ESA). This Sustainability Report is intended to inform and help frame the efforts of the Working Group. The Sustainability Report noted that it is critically important for any pension plan for public-sector workers to be sustainable so that the retirement income of retirees and active members is secure. Management will continue to monitor the initiatives of this Working Group and potential impacts of any recommendations for Hydro One accordingly. To ensure the sustainability of the Hydro One Pension Plan, our company has implemented a gradual increase in the amount of employee contributions to the plan.

Outsourcing Agreements

The current agreement with Inergi LP (Inergi), an affiliate of Capgemini Canada Inc., expires on February 28, 2015. On November 28, 2014, we entered into an agreement with Inergi (Inergi Agreement), the service provider selected through a competitive procurement process which began in 2013, for second-generation back office and IT outsourcing services for a term of 58 months, commencing March 1, 2015 to December 31, 2019. Under the agreement, Inergi will provide us with settlements, source to pay services, pay operations services, information technology and finance and accounting services.

Coincident with the conclusion of negotiations on the Inergi Agreement, we reached agreement with Inergi to provide us with second-generation customer service operations outsourcing services for a fixed period of three years beginning March 1, 2015 to February 28, 2018.

In its re-tendering initiative, Hydro One set out four objectives for its new outsourcing agreements: continually improved value for money; providing operational flexibility; delivery of services to reflect global best practices; and robust, effective performance management and governance. This agreement achieves those objectives and supports our company's key strategic objectives, while allowing the Company to focus on its core activities of maintaining, planning and operating our Transmission and Distribution Businesses and delivering excellent service to our customers. The agreement will see cost savings on annual base fees while at the same time providing service delivery improvements, as we continue our ongoing efforts to reduce costs and drive more efficiency in our business.

In September 2014, we entered into an agreement with Brookfield Johnson Controls Canada LP (Brookfield), a service provider selected through a competitive procurement process, for facilities management services for a term of ten years, effective January 1, 2015 to December 31, 2024, with the option to renew for an additional term of three years. Over the term of the contract we will transition the facilities management of all of our facilities. Under the agreement, Brookfield will provide us with facilities management and execution of certain capital projects as deemed required by our company. The Brookfield Agreement has a value of up to approximately $658 million over the ten-year term of the agreement, including the facilities management portion of the contract, plus a variable amount of capital work depending on the needs that may arise as determined by our company, with no minimum capital work guarantee.

Details of our contractual obligations under our outsourcing agreements can be found in the section "Liquidity and Capital Resources – Summary of Contractual Obligations and Other Commercial Commitments."

ANNUAL RESULTS OF OPERATIONS

Year ended December 31 (millions of Canadian dollars)	**2014**	2013	$ Change	% Change
Revenues	**6,548**	6,074	474	8
Purchased power	**3,419**	3,020	399	13
Operation, maintenance and administration	**1,192**	1,106	86	8
Depreciation and amortization	**722**	676	46	7
	5,333	4,802	531	11
Income before financing charges and provision for payments in lieu of corporate income taxes	**1,215**	1,272	(57)	(4)
Financing charges	**379**	360	19	5
Income before provision for payments in lieu of corporate income taxes	**836**	912	(76)	(8)
Provision for payments in lieu of corporate income taxes	**89**	109	(20)	(18)
Net income	**747**	803	(56)	(7)
Net income (loss) attributable to noncontrolling interest	**(2)**	–	(2)	(100)
Net income attributable to Shareholder of Hydro One	**749**	803	(54)	(7)

Revenues

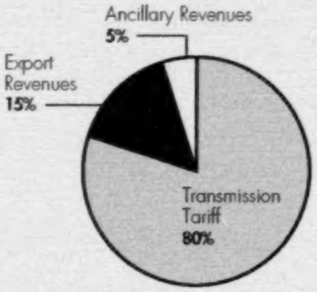
Year ended December 31 (millions of Canadian dollars)	**2014**	2013	$ Change	% Change
Transmission	**1,588**	1,529	59	4
Distribution	**4,903**	4,484	419	9
Other	**57**	61	(4)	(7)
	6,548	6,074	474	8
Average annual Ontario 60-minute peak demand (MW)[1]	**20,596**	21,493	(897)	(4)
Distribution – units distributed to our customers (TWh)[1]	**29.8**	29.8	–	–

[1] System-related statistics are preliminary.

Transmission

Transmission revenues primarily consist of our transmission tariff, which is based on the monthly peak electricity demand across our high-voltage network. The tariff is designed to recover revenues necessary to support a transmission system with sufficient capacity to accommodate the maximum expected demand. Demand is primarily influenced by weather and economic conditions. Transmission revenues also include export revenues associated with transmitting excess generation to surrounding markets, ancillary revenues primarily attributable to maintenance services provided to generators, and secondary use of our land rights.

Composition of 2014 Transmission Revenues



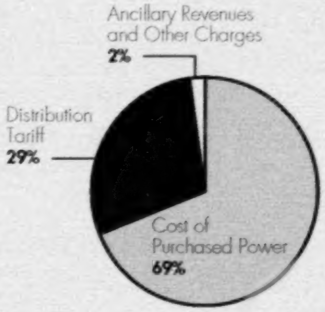
Our 2014 transmission revenues increased by $59 million, or 4%, compared to 2013. The components of the increase include the following:

- $90 million increase due to new transmission rates effective January 1, 2014 approved by the OEB in January 2014;
- $42 million increase due to the OEB's approval of increased export service revenues in recognition of higher electricity exports to other jurisdictions and the disposition of certain OEB-approved transmission regulatory accounts;
- $45 million decrease due to lower average Ontario 60-minute peak demand in 2014. The lower electricity demand in 2014 was mainly due to milder weather in the summer and fall of 2014, compared to 2013; and
- $28 million decrease due to ancillary transmission revenues, primarily associated with OEB-approved regulatory accounts.

Distribution

Distribution revenues include our distribution tariff and amounts to recover the cost of purchased power used by the customers of our Distribution Business. Accordingly, our distribution revenues are influenced by the amount of electricity we distribute, the cost of purchased power and our distribution tariff rates. Distribution revenues also include minor ancillary distribution service revenues, such as fees related to the joint use of our distribution poles by the telecommunications and cable television industries, as well as miscellaneous charges such as charges for late payments.

Composition of 2014 Distribution Revenues



Our 2014 distribution revenues increased by $419 million, or 9%, compared to 2013. The components of the increase include the following:

- $399 million increase due to the recovery of higher purchased power costs, as described below under "Purchased Power;"
- $12 million increase due to new distribution rates effective January 1, 2014 approved by the OEB in December 2013; and
- $8 million increase due to ancillary distribution revenues, primarily associated with OEB-approved regulatory accounts.

Purchased Power

Purchased power costs are incurred by our Distribution Business and represent the cost of purchased electricity delivered to customers within our distribution service territory. These costs comprise the wholesale commodity cost of energy, the IESO wholesale market service charges, and transmission charges levied by the IESO. The commodity cost of energy is based on the OEB's RPP or the market price for electricity. A discussion of the electricity rates can be found in the section "Regulation – Regulatory Proceedings – Electricity Rates."

Our purchased power costs increased by $399 million, or 13%, in 2014, compared to 2013. The components of the increase include the following:

- $291 million increase resulting from higher purchased power costs for customers who are not eligible for the RPP;
- $78 million increase resulting from the impact of changes in the OEB's RPP rates for residential and other eligible customers;

- $26 million increase resulting from the OEB transmission rate decision effective January 1, 2014;
- $10 million increase due to wholesale market service charges levied by the IESO;
- $4 million increase resulting from the IESO's Smart Metering Entity charge effective May 1, 2013; and
- $10 million decrease due to lower energy consumption in 2014, mainly resulting from a milder summer and a warmer fall in 2014.

Operation, Maintenance and Administration

Our operation, maintenance and administration costs consist of labour, which is substantially established under collective bargaining agreements, and materials, equipment and purchased services, which are subject to public tenders. Key enablers of the successful implementation of our work programs are our human and material resourcing strategies. Our human resources strategy is focused on hiring through our apprenticeship program and our association with universities, colleges and our unions, as well as skills development and retention, including earlier identification and more rapid development of staff who demonstrate management potential. Our skilled labour pool primarily consists of line, forestry, construction and stations staff who live and work across the province.

Our operation, maintenance and administration expenditures include work program costs and costs to support the operation and maintenance of the transmission and distribution systems. Also included in these costs are payments in lieu of property taxes related to our transmission and distribution lines, stations and buildings. Our transmission operation, maintenance and administration costs are incurred to sustain our high-voltage transmission stations, lines and rights-of-way, and include preventive and corrective maintenance costs related to our power equipment, overhead transmission lines, transmission station sites, and brush control. Our distribution operation, maintenance and administration costs are required to maintain our low-voltage distribution system, and include costs related to distribution line clearing and brush control, line maintenance and repair, as well as land assessment and remediation (LAR). Our company continues to focus on managing its costs, while continuing to complete our planned work programs for both our Transmission and Distribution Businesses.

Year ended December 31 (millions of Canadian dollars)	**2014**	2013	$ Change	% Change
Transmission	**394**	375	19	5
Distribution	**742**	672	70	10
Other	**56**	59	(3)	(5)
	1,192	1,106	86	8

Transmission

Our 2014 transmission operation, maintenance and administration costs increased by $19 million, or 5%, compared to 2013.

Our 2014 transmission work program costs were $240 million, compared to $237 million in 2013, an increase of $3 million. The increase is mainly due to the following:

- increased forestry expenditures related to brush control and line clearing on our transmission rights-of-way;
- a higher volume of corrective and preventive maintenance on power equipment and overhead lines; and
- higher transmission site facilities maintenance requirements.

Our 2014 transmission support costs were $154 million, compared to $138 million in 2013, an increase of $16 million. The increase is mainly due to the following:

- a one-time reduction to our provision for payments in lieu of property taxes in 2013 related to transmission stations for the years 1999 to 2012, inclusive, following the finalization of the related regulations and receipt of a final assessment of our property tax returns;
- partially offset by lower expenditures due to the recovery of insurance proceeds for the 2013 floods at our Richview and Manby transmission stations; and
- increased attribution of overheads to capital project expenditures in 2014.

Distribution

Our 2014 distribution operation, maintenance and administration costs increased by $70 million, or 10%, compared to 2013.

Our 2014 distribution work program costs were $599 million, compared to $515 million in 2013, an increase of $84 million. The increase is mainly due to the following:

- our customer service recovery initiatives and the increase in our bad debt expense, resulting from higher electricity consumption due to a substantially colder than normal winter, combined with higher electricity prices and the suspension of certain collection tools and efforts during several months in 2014. We resumed some of our collection tools and efforts in September 2014.

Our 2014 distribution support costs were $143 million, compared to $157 million in 2013, a decrease of $14 million. The decrease is mainly due to the following:

- decreased expenditures in 2014 related to CIS, as it was placed in-service in May 2013.

Depreciation and Amortization

Our 2014 depreciation and amortization costs increased by $46 million, or 7%, compared to 2013. This increase was primarily attributable to higher property, plant and equipment depreciation expense in 2014, mainly related to the growth in capital assets as we continue to place new assets in-service, consistent with our ongoing capital work program.

Financing Charges

Our 2014 financing charges increased by $19 million, or 5%, compared to 2013. The increase is primarily due to the following:

- an increase in interest expense on our long-term debt due to a higher average level of debt;
- partially offset by a lower average interest rate.

Provision for Payments in Lieu of Corporate Income Taxes

The provision for payments in lieu of corporate income taxes (PILs) decreased by $20 million, or 18%, to $89 million in 2014, compared to 2013. The decrease is primarily due to lower levels of pre-tax income in 2014 compared to 2013.

Net Income

Our 2014 net income attributable to the Shareholder of Hydro One decreased by $54 million, or 7%, to $749 million, compared to 2013. The decrease is primarily due to the following:

- $70 million increase in our 2014 distribution operation, maintenance and administration costs, mainly due to our customer service recovery initiatives and the increase in our bad debt expense, resulting from higher electricity consumption due to a substantially colder than normal winter, combined with higher electricity prices and the suspension of certain collection tools and efforts during several months in 2014;
- $46 million increase in our 2014 depreciation and amortization costs, mainly due to higher property, plant and equipment depreciation expense in 2014, related to the growth in capital assets as we continue to place new assets in-service, consistent with our ongoing capital work program; and
- partially offset by a $59 million increase in our 2014 transmission revenues, mainly due to new OEB-approved 2014 transmission rates.

QUARTERLY RESULTS OF OPERATIONS

The following table sets forth unaudited quarterly information for each of the eight quarters, from the quarter ended March 31, 2013 through to December 31, 2014. This information has been derived from our unaudited interim Consolidated Financial Statements and our audited annual Consolidated Financial Statements, which include all adjustments, consisting only of normal recurring adjustments, necessary for fair presentation of our financial position and results of operations for those periods. These operating results are not necessarily indicative of results for any future period and should not be relied upon to predict our future performance.

(millions of Canadian dollars)	**2014**				2013			
Quarter ended	**Dec. 31**	**Sept. 30**	**Jun. 30**	**Mar. 31**	Dec. 31	Sept. 30	Jun. 30	Mar. 31
Total revenue	**1,662**	**1,556**	**1,566**	**1,764**	1,557	1,542	1,403	1,572
Net income attributable to Shareholder of Hydro One	**221**	**173**	**115**	**240**	160	218	168	257
Net income to common Shareholder of Hydro One	**216**	**169**	**110**	**236**	155	214	163	253

Electricity demand generally follows normal weather-related variations, and consequently, our electricity-related revenues and profit, all other things being equal, would tend to be higher in the first and third quarters than in the second and fourth quarters.

2014 Fourth Quarter Results of Operations

Three months ended December 31 (millions of Canadian dollars)	**2014**	2013	$ Change	% Change
Revenues	**1,662**	1,557	105	7
Purchased power	**893**	794	99	12
Operation, maintenance and administration	**247**	286	(39)	(14)
Depreciation and amortization	**190**	184	6	3
	1,330	1,264	66	5
Income before financing charges and provision for payments in lieu of corporate income taxes	**332**	293	39	13
Financing charges	**98**	93	5	5
Income before provision for payments in lieu of corporate income taxes	**234**	200	34	17
Provision for payments in lieu of corporate income taxes	**15**	40	(25)	(63)
Net income	**219**	160	59	37
Net income (loss) attributable to noncontrolling interest	**(2)**	–	(2)	(100)
Net income attributable to Shareholder of Hydro One	**221**	160	61	38

Our total revenues for the three months ended December 31, 2014 were $1,662 million, compared to $1,557 million during the same period in 2013, an increase of $105 million or 7%. The increase is mainly due to the following:

- the recovery of higher purchased power costs;
- new transmission and distribution rates effective January 1, 2014;
- the OEB's approval of increased export service revenues in recognition of higher electricity exports to other jurisdictions and the disposition of certain OEB-approved transmission regulatory accounts;

- partially offset by lower average Ontario 60-minute peak demand and energy consumption in the fourth quarter of 2014, mainly due to milder weather in the fall of 2014; and
- lower ancillary revenues, primarily associated with OEB-approved regulatory accounts.

Our purchased power costs for the three months ended December 31, 2014 were $893 million, compared to $794 million during the same period in 2013, an increase of $99 million or 12%. The increase is mainly due to the following:

- higher purchased power costs for customers who are not eligible for the RPP;
- partially offset by lower energy consumption in the fourth quarter of 2014, mainly due to milder weather in the fall of 2014;
- wholesale market service charges levied by the IESO; and
- OEB transmission rate decision effective January 1, 2014.

Our operation, maintenance and administration costs for the three months ended December 31, 2014 were $247 million, compared to $286 million during the same period in 2013, a decrease of $39 million or 14%. The decrease is mainly due to the following:

- decreased distribution operation, maintenance and administration costs, primarily due to lower storm response expenditures as a result of lower storm activity in 2014, compared to 2013; and
- decreased expenditures related to brush control and distribution line maintenance work.

Our depreciation and amortization costs for the three months ended December 31, 2014 were $190 million, compared to $184 million during the same period in 2013, an increase of $6 million or 3%. The increase is mainly due to higher property, plant and equipment depreciation expense in 2014, mainly related to the growth in capital assets as we continue to place new assets in-service, consistent with our ongoing capital work program.

Our financing charges for the three months ended December 31, 2014 were $98 million, compared to $93 million during the same period in 2013, an increase of $5 million or 5%. The increase is mainly due to the following:

- an increase in interest expense on our long-term debt due to a higher average level of debt; and
- partially offset by a lower average interest rate.

Our provision for PILs for the three months ended December 31, 2014 was $15 million, compared to $40 million during the same period in 2013, a decrease of $25 million or 63%. The decrease is due to the following:

- changes in net temporary differences, such as capital cost allowance in excess of depreciation, deductions for pension payments made in excess of amounts expensed for accounting purposes, and interest deducted for tax purposes in excess of interest expensed for accounting purposes; and
- partially offset by higher pre-tax income for the three months ended December 31, 2014 compared to the same period in 2013.

Net income attributable to the Shareholder of Hydro One for the three months ended December 31, 2014 was $221 million, compared to $160 million during the same period in 2013, an increase of $61 million or 38%. The increase is mainly due to the following:

- decreased distribution operation, maintenance and administration costs, primarily due to lower storm response expenditures as a result of lower storm activity in 2014, compared to 2013, and decreased expenditures related to brush control and distribution line maintenance work;
- a decrease in our provision for PILs, primarily due to changes in net temporary differences; and
- an increase in our 2014 transmission revenues, mainly due to new OEB-approved 2014 transmission rates.

LIQUIDITY AND CAPITAL RESOURCES

Our primary sources of liquidity and capital resources are funds generated from our operations, debt capital market borrowings and bank financing. These resources will be used to satisfy our capital resource requirements, which continue to include our capital expenditures, servicing and repayment of our debt, and dividends.

Summary of Sources and Uses of Cash

Year ended December 31 (millions of Canadian dollars)	**2014**	2013
Operating activities	**1,256**	1,404
Financing activities		
Long-term debt issued	**628**	1,185
Long-term debt retired	**(776)**	(600)
Amount contributed by noncontrolling interest	**72**	–
Dividends paid	**(287)**	(218)
Investing activities		
Capital expenditures	**(1,504)**	(1,387)
Acquisition of Norfolk Power	**(66)**	–
Proceeds from investment	**250**	–
Other financing and investing activities	**(38)**	(14)
Net change in cash and cash equivalents	**(465)**	370

Operating Activities

Net cash from operating activities decreased by $148 million to $1,256 million in 2014, compared to 2013. The decrease was primarily due to the following:

- lower 2014 net income, compared to 2013;
- changes in accrual balances, mainly related to timing of capital projects;
- changes in regulatory accounts, including the retail settlement and external revenue variance accounts; and
- partially offset by higher property, plant and equipment depreciation expense in 2014, mainly related to the growth in capital assets as we continue to place new assets in-service, consistent with our ongoing capital work program.

Financing Activities

Short-term liquidity is provided through funds from operations, our Commercial Paper Program, under which we are authorized to issue up to $1,000 million in short-term notes with a term to maturity of less than 365 days, and our revolving credit facility.

Our Commercial Paper Program is supported by our $1,500 million committed revolving credit facility with a syndicate of banks, which matures in June 2019. The short-term liquidity under this program and anticipated levels of funds from operations should be sufficient to fund our normal operating requirements.

At December 31, 2014, we had $8,923 million in long-term debt outstanding, including the current portion. Our notes and debentures mature between 2015 and 2064. Long-term financing is provided by our access to the debt markets, primarily through our Medium-Term Note (MTN) Program. The maximum authorized principal amount of medium-term notes issuable under this program is $3,000 million. At December 31, 2014, $1,187 million remained available until October 2015.

We rely on debt financing through our MTN Program and our Commercial Paper Program to repay our existing indebtedness and fund a portion of our capital expenditures. The credit ratings assigned to our debt securities by external rating agencies are important to our ability to raise capital and funding to support our business operations. Maintaining strong credit ratings allows us to access capital markets on competitive terms. A material downgrade of our credit ratings would likely increase our cost of funding significantly, and our ability to access funding and capital through the capital markets could be reduced. Our corporate credit ratings from approved rating organizations are as follows:

	Rating	
Rating Agency	**Short-term Debt**	**Long-term Debt**
DBRS Limited	R-1 (middle)	A (high)
Moody's Investors Service Inc.	Prime-1	A1
Standard & Poor's Rating Services Inc. (S&P)	A-1	A+

We have the customary covenants normally associated with long-term debt. Among other things, our long-term debt covenants limit our permissible debt as a percentage of our total capitalization, limit our ability to sell assets, and impose a negative pledge provision, subject to customary exceptions. The credit agreements related to our credit facilities have no material adverse change clauses that could trigger default. However, the credit agreements require that we provide notice to the lenders of any material adverse change within three business days of the occurrence. The agreements also provide limitations that debt cannot exceed 75% of total capitalization and that third party debt issued by our subsidiaries cannot exceed 10% of the total book value of our assets. We were in compliance with all of these covenants and limitations as at December 31, 2014.

In 2014, we issued $628 million of long-term debt under our MTN Program, compared to $1,185 million of long-term debt issued in 2013. In 2014, we also repaid $750 million in maturing long-term debt, compared to $600 million of long-term debt repaid in 2013. In addition, long-term debt totalling $26 million assumed on the Norfolk Power acquisition was repaid in September 2014. We had no short-term notes outstanding at December 31, 2014 or December 31, 2013.

Common share dividends are declared at the sole discretion of our Board of Directors, and are recommended by management based on results of operations, maintenance of the deemed regulatory capital structure, financial condition, cash requirements, and other relevant factors, such as industry practice and Shareholder expectations. Common share dividends pertaining to our quarterly financial results are generally declared and paid in the following quarter.

During 2014, we paid dividends to the Province in the amount of $287 million, consisting of $269 million in common share dividends and $18 million in preferred share dividends, compared to dividends of $218 million, consisting of $200 million of common share dividends and $18 million of preferred share dividends, paid to the Province in 2013.

Our objectives with respect to our capital structure are to maintain effective access to capital on a long-term basis at reasonable rates and to deliver appropriate financial returns to our Shareholder.

Investing Activities

During 2014, we continued to focus on making important investments in our transmission and distribution systems to address our aging power system infrastructure, improve our systems' reliability and performance, and improve service to our customers. We made capital investments totalling $1,530 million in 2014, compared to $1,394 million of capital investments in 2013, and have placed $1,574 million of new assets in-service in 2014, compared to $1,491 million of new assets placed in-service in 2013.

Capital investments consist of cash capital expenditures and related accruals. Capital investments primarily relate to sustaining, enhancing and reinforcing our transmission and distribution infrastructure.

Year ended December 31 (millions of Canadian dollars)	**2014**	2013	$ Change	% Change
Transmission	**845**	714	131	18
Distribution	**680**	673	7	1
Other	**5**	7	(2)	(29)
Total capital investments	**1,530**	1,394	136	10

Transmission Capital Investments

Our 2014 transmission capital investments were $845 million, compared to $714 million in 2013, an increase of $131 million or 18%, primarily due to sustainment programs to address our aging infrastructure. Given the aging of our infrastructure, we have ongoing investment plans which are designed to reliably power our economy and to support the innovation that can be expected over the next decade.

The following table presents the main components of our transmission capital investments during 2014 and 2013.

Year ended December 31 (millions of Canadian dollars)	**2014**	2013	$ Change	% Change
Sustainment	**625**	481	144	30
Development	**132**	170	(38)	(22)
Other	**88**	63	25	40
Total transmission capital investments	**845**	714	131	18

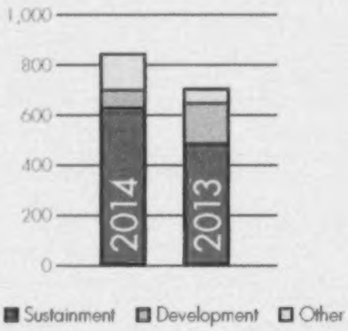
Sustainment Transmission Capital Investments

Our current transmission sustainment programs include protection and control systems, wood poles, breakers and high-voltage instrument transformer replacements. Our 2014 transmission sustainment capital investments were $625 million, compared to $481 million in 2013, an increase of $144 million or 30%. The increase was mainly due to the following:

- several system re-investments, including the Gerrard and Timmins transmission stations and new type of breakers at our Bruce Transmission Station, which progressed in 2014, as well as completed projects, such as the Pinard Transmission Station Breakers and the Wallaceburg Transmission Station;
- several replacements of end-of-life power transformers at our Pembroke Transmission Station in eastern Ontario, and our Hanover, Allanburg, and Elmira transmission stations in southwestern Ontario, as well as the emergency replacement of a unit at the Trafalgar Transmission Station;
- increased work within our station and lines equipment replacement and refurbishment projects and programs, including our investment to address the condition of the conductors on the 170 kilometre 230 kV circuit from the Chats Falls Switching Station to the Havelock Transmission Station in southeastern Ontario, and increased work on overhead lines wood pole structure replacements; and
- increased volume of replacements related to addressing aging protection and control equipment.

Transmission Capital Investments

(millions of dollars)



Development Transmission Capital Investments

Our current transmission development projects include transmission system upgrades, local area supply projects, and inter-area network projects. These investments will expand and reinforce power reliability for electricity customers throughout the province, including our residential and industrial customers. Our 2014 development capital investments to expand and reinforce our transmission system were $132 million, compared to $170 million in 2013, a decrease of $38 million or 22%. The decrease was mainly due to the following:

- the successful completion of our Sundusk and Summerhaven Switching Stations upgrades in 2013 to incorporate renewable energy into our transmission system; and
- reduced expenditures related to some of our major projects which were completed in 2014, such as the Lambton to Longwood Transmission Upgrade Project, the Barwick Transmission Station, and the Allanburg Transmission Station to ensure mandatory transmission system standards are met.

Other Transmission Capital Investments

Our 2014 other transmission capital investments were $88 million, compared to $63 million in 2013, an increase of $25 million or 40%. The increase was mainly due to the following:

- the development phase investment in our Network Management System Project, a critical operating tool used for monitoring and control of our transmission system;
- the investment in our Payroll Transformation Project to realize various process efficiencies; and
- partially offset by a decrease from the higher investments in 2013 as a result of emergency flood restoration work at our Richview Transmission Station resulting from a major rainstorm in July 2013.

Major Transmission Projects

Our company successfully advanced or completed a number of transmission capital investments projects during 2014. The following table summarizes the status of our major projects at December 31, 2014:

Project Name	**Location**	**Type**	**Planned In-Service Date**	**Approved Budget**	**Capital Cost To-Date**	**Current Status**
Lambton to Longwood Transmission Upgrade	Sarnia area to west of London area Southwestern Ontario	Transmission line upgrade	2014	$41 million	$24 million	Placed in-service in September 2014
Barwick Transmission Station	Rainy River/Fort Frances Northwestern Ontario	New transmission station	2014	$25 million	$21 million	Placed in-service in September 2014
Allanburg Transmission Station	Niagara area Southwestern Ontario	Transmission station upgrade	2014	$33 million	$29 million	Placed in-service in December 2014
Toronto Midtown Transmission Reinforcement	Toronto Southwestern Ontario	New transmission line	2015	$115 million	$83 million	Project is in progress
Guelph Area Transmission Refurbishment	Guelph area Southwestern Ontario	Transmission line upgrade	2016	$103 million	$24 million	Project is in progress
Manby Transmission Station	Toronto Southwestern Ontario	Transmission station upgrade	2016	$24 million	$14 million	Project is in progress
Clarington Transmission Station	Oshawa area Eastern GTA	New transmission station	2017	$297 million	$42 million	Project is in progress
Supply to Essex County Transmission Reinforcement	Windsor-Essex area Southwestern Ontario	New transmission line and station	2018	To be determined	–	Section 92 application filed with OEB in January 2014
Northwest Bulk Transmission Line	Thunder Bay Northwestern Ontario	New transmission line	As early as 2020	To be determined	–	OPA recommendation letter received in October 2014

Lambton to Longwood Transmission Upgrade

Our Lambton to Longwood Transmission Upgrade project involved the upgrade of approximately 70 kilometres of 230 kV double-circuit transmission line between our Lambton and Longwood transmission stations in southwestern Ontario. The investment refurbished 36 tower foundations, replaced the conductor with a higher capacity wire and replaced insulators along the line. This project involved an innovative new technology that allowed the vast majority of the towers to remain in place, and will enable approximately 500 MW of additional clean energy to be connected to the grid. The additional capacity on the grid will also contribute to meeting provincial energy supply targets for installed non-hydroelectric renewable generation by 2021.

Barwick Transmission Station

Our Barwick Transmission Station provides more capacity for communities between Rainy River and Fort Frances in northwestern Ontario, thereby strengthening the reliability of the power supply for both residential and commercial customers in the area. The Barwick Transmission Station consists of two 115 kV/44 kV transformers and allows for shorter spans of 44 kV power lines to connect customers to our system, ultimately improving the reliability of their power supply. The project involved in-house construction crews, local vendors and labour from the Rainy River First Nation community.

Allanburg Transmission Station

As a result of new generation connections and various transmission project upgrades in the Niagara area of southwestern Ontario, the Allanburg Transmission Station 115 kV switchyard short circuit level has increased and exceeded breaker capability limits. Consequently, upgrade work was required to replace 15 end-of-life breakers with upgraded short circuit capability in accordance with the TSC standards.

Toronto Midtown Transmission Reinforcement

Supply to the midtown Toronto area is currently provided by three 115 kV circuits between the Leaside Transmission Station and the Wiltshire Transmission Station. These circuits also supply the Bridgman and Dufferin Transmission Stations and provide load transfer capability between the Leaside and Manby transmission stations. The Toronto Midtown Transmission Reinforcement project includes the replacement of an aging underground cable which is nearing its end of life; the installation of an additional 115 kV circuit between the Leaside and Bridgman transmission stations to relieve loading on the existing circuits which are currently operating above their capacity; and the installation of new equipment at the Leaside Transmission Station, and Bayview, Birch and Bridgman Junctions. These transmission infrastructure reinforcements are intended to reduce the risk of power outages, improve reliability for electricity customers, and provide additional supply capability to meet future load growth in midtown Toronto as well as areas to the west.

Guelph Area Transmission Refurbishment

The Guelph Area Transmission Refurbishment Project, an upgrade of a transmission line and transmission stations in Guelph and the surrounding area, includes the installation of two new autotransformers at the existing Cedar Transmission Station, an upgrade of approximately five kilometres of an existing transmission line from 115 kV to 230 kV in south-central Guelph, and an upgrade of the existing Guelph North Junction to a switching station by installing new facilities and fencing. These refurbishments will reinforce the electricity supply and will minimize the impact of any major transmission outages on area customers.

Manby Transmission Station

The Manby Transmission Station project will upgrade the station short circuit capability and install higher rated breakers, which will permit incorporation of new renewable generation in the central Toronto area. Upgrade work requires the replacement of 16 end-of-life breakers and other components in the 115 kV Manby switchyard.

Clarington Transmission Station

To accommodate the eventual closure of the Pickering Nuclear Generating Station, the Clarington Transmission Station will provide additional autotransformer capacity to reliably supply load in the eastern GTA. Upon completion, the Clarington Transmission Station will consist of two 500/230 kV autotransformers and a 230 kV switchyard, and will connect to the existing 230 kV and 500 kV transmission lines. The project will enable future electricity demand growth in the local area and provide the area with the necessary facilities to ensure a safe, reliable supply of electricity to existing and future customers.

Supply to Essex County Transmission Reinforcement Project

On January 22, 2014, Hydro One Networks submitted a Leave to Construct application to the OEB under Section 92 of the *OEB Act* to construct a new 13-kilometre 230 kV double-circuit transmission line in the Windsor-Essex region. The new transmission line will connect to a proposed transmission station in the Municipality of Leamington and an existing 230 kV transmission line between Chatham and Windsor. The new transmission line and transmission station will address future growth in electricity demand and anticipated expansion in the local agricultural sector and improve the reliability of electricity supply in the broader Windsor-Essex region.

Northwest Bulk Transmission Line

In November 2013, the Minister of Energy issued a Directive to the OEB, which in turn issued a Decision and Order on January 9, 2014, to amend the transmission licence of Hydro One Networks to develop and seek approval for the Northwest Bulk Transmission Line Project, an expansion and reinforcement of the transmission system in the area west of Thunder Bay in northwestern Ontario. The project consists of a new transmission line that would increase transmission capacity and maintain the reliability of electricity supply to meet forecasted electricity demand growth and accommodate new generation capacity. Over the long term, it would also enhance the potential for development and connection of renewable energy facilities. Because of its importance to the region, this new line has been identified as a priority project in Ontario's LTEP. The Northwest Bulk Transmission Line Project will be developed by our company in cooperation with Infrastructure Ontario. The scope and timing of the project shall be in accordance with the recommendations of the OPA.

On October 1, 2014, Hydro One received a letter from the OPA outlining the scope and timing of the Northwest Bulk Transmission Line Project. The scope of the development work will include preliminary design and engineering, cost estimation, public engagement and consultation, routing and siting, and the preparation of an environmental assessment in support of this project. Hydro One is currently initiating the development work for the project and discussions are ongoing with Infrastructure Ontario on the project plan and related accountabilities.

Other Transmission Capital Investments

Pan American (Pan Am) Games

The Pan Am Games project tracking initiative is underway to ensure that we provide a high level of electricity supply reliability to the Pan Am and Parapan Am Games during the summer of 2015, and that operating, maintenance and capital work plans are coordinated across lines of business to minimize outage risks to the venues hosting the 2015 Pan Am and Parapan Am Games. Key major capital projects and site-specific maintenance work in the GTA are being monitored on a monthly basis to ensure our customer commitments are met. This work will ultimately benefit all of our customers in the GTA.

Niagara Reinforcement Project

This project comprises the construction of 76 kilometres of 230 kV line from our Allanburg Transmission Station in the Niagara area to our Middleport Transmission Station in the Hamilton area. The Niagara Reinforcement Project status is considered substantially on time, with the exception that some project work has been delayed due to access issues related to Aboriginal land claims on a section of the line.

Distribution Capital Investments

Our 2014 distribution capital investments were $680 million, compared to $673 million in 2013, an increase of $7 million or 1%, primarily due to our distribution sustainment programs to address our aging infrastructure.

The following table presents the main components of our distribution capital investments during 2014 and 2013.

Year ended December 31 (millions of Canadian dollars)	**2014**	2013	$ Change	% Change
Sustainment	**356**	324	32	10
Development	**236**	235	1	–
Other	**88**	114	(26)	(23)
Total distribution capital investments	**680**	673	7	1

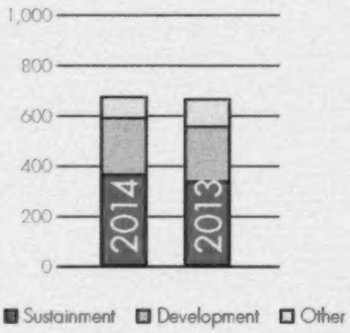
Sustainment Distribution Capital Investments

Our current distribution sustainment programs include wood pole and meter replacements, emergency work for storm restoration, distribution station refurbishments and upgrades, and work related to joint-use and relocation of our distribution lines. Our 2014 distribution sustainment capital investments were $356 million, compared to $324 million in 2013, an increase of $32 million or 10%. The increase is mainly due to the following:

- increased investments in meter replacements, including Itron Sentinel 16S meter replacements and Field Metering Services installations;
- higher volume of end-of-life wood pole replacements;
- increased focus on capital lines work, mainly due to the lines large sustainment initiatives program;
- increased work within our station refurbishment programs due to more refurbishments accomplished in 2014; and
- partially offset by less storm restoration work in 2014 due to lower storm activity compared to 2013.

Distribution Capital Investments

(millions of dollars)



Development Distribution Capital Investments

Our current development projects to expand and reinforce our distribution network include new customer connections and upgrades, system capability reinforcement projects, line transfers requested by our customers, and connections to new generation facilities. Our 2014 distribution development capital expenditures were $236 million, compared to $235 million in 2013, an increase of $1 million. The increase is mainly due to the following:

- increased work for subdivision connections, new customer connections, and upgrades;
- the purchase of retail revenue meters for all new connections and service upgrades; and
- partially offset by less lines and stations work related to upgrading and adding capacity to our distribution system.

Other Distribution Capital Investments

Our 2014 other distribution capital expenditures were $88 million, compared to $114 million in 2013, a decrease of $26 million or 23%. The decrease is mainly due to the following:

- decreased expenditures in 2014 related to CIS, as it was placed in-service in May 2013;
- decrease due to higher investments in 2013 as a result of emergency flood restoration work at our Richview Transmission Station resulting from a major rainstorm in July 2013; and
- partially offset by the investment in our Payroll Transformation Project to realize various process efficiencies.

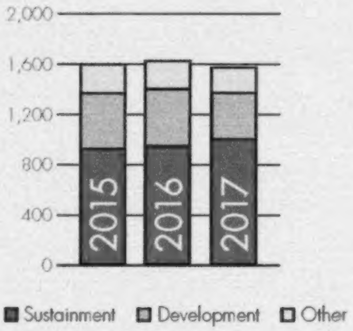
Future Capital Investments

Our capital investments for 2015 are budgeted at approximately $1,600 million. Our 2015 capital budgets for our Transmission and Distribution Businesses are approximately $900 million and $700 million, respectively. Consolidated capital investments are expected to be approximately $1,625 million in 2016 and $1,575 million in 2017. These investment levels reflect our continued sustainment focus on our aging infrastructure. Our sustainment program capital investments are expected to be approximately $925 million in 2015, $950 million in 2016 and $1,000 million in 2017. Our development capital investments are expected to be approximately $450 million in 2015,

$450 million in 2016, and $375 million in 2017. Our development projects include the inter-area network upgrades that reflect supply mix policies, local area supply improvements, the ADS Project, new load and generation connections and requirements to enable DG, and customer demand work. Other capital investments are expected to be $225 million in 2015, $225 million in 2016, and $200 million in 2017. This includes investments in operating infrastructure integration, information technology (IT), fleet services and facilities, and real estate. Our future capital investments amounts do not include future LDC acquisitions.

Hydro One's plans to maintain, refurbish or replace existing facilities are developed on the basis of maintenance standards, asset condition assessments and end-of-life criteria specific to each type of equipment. Priorities are assigned to each type of investment based on the risks that it mitigates. In addition, investments that are cross-functional and/or require IT involvement are governed by a productivity framework with substantive benefits. These capital investment plans are also included in our rate filings submitted to the OEB for approval.

Future Capital Investments
(millions of dollars)



Transmission

Transmission capital investments are incurred to manage the replacement and refurbishment of our aging transmission infrastructure in order to ensure a continued reliable supply of energy to customers throughout the province. Our sustainment program future capital investments include the replacement and/or refurbishment of end-of-life air blast circuit breakers and switchgear, high-voltage underground cables, high-voltage circuits and power transformers. Also, given the current age of our assets and infrastructure and to achieve significant cost efficiencies, we have moved to a more integrated station and circuit centric refurbishments approach than has been undertaken historically in order to address and bundle component and refurbishment replacements that would have occurred over time into one project. These investments are necessary to ensure that we maintain our current levels of supply to our customers and continue to meet all regulatory, compliance, safety and environmental objectives.

Our future development capital investments include the Clarington Transmission Station Project to install additional autotransformer capacity in the eastern GTA; the Guelph Area Transmission Refurbishment Project, an upgrade of a transmission line and transmission stations in south-central Guelph; investments in ADS; requirements to enable DG; the Supply to Essex County Transmission Reinforcement Project, a new transmission line in the Windsor-Essex region; and the Toronto Midtown Transmission Reinforcement Project, a new circuit in midtown Toronto and the refurbishment of an underground cable. Development capital investments also include the connection of new generation projects to the transmission system; however, these investments are largely funded by the connecting generation customers.

Based on the OEB's framework for competitive designation for the development of eligible transmission projects, we did not include in our budgeted future capital investments any projects that could meet the definition of expansions. We do not plan to undertake large capital investments without a reasonable expectation of recovering them through our rates.

The actual timing and investments of many development projects are uncertain as they are dependent upon various regulatory approvals, negotiations with customers, neighbouring utilities and other stakeholders, and consultations with First Nations and Métis communities. Projects are also dependent upon the timing and level of generator contributions for enabling facilities.

Distribution

Distribution capital investments include the sustainment of our infrastructure. Our core work will continue to focus on maintaining the performance of our aging distribution asset base through renewal and refurbishment activities. Planned capital investments include the continued replacements of equipment and components that are beyond their expected service life, as well as increased wood pole replacements and distribution station refurbishments. Sustainment capital investments related to the smart metering project will decrease through 2016.

Distribution development capital investments are expected to be relatively stable through 2016, with the exception of capital contributions for capacity improvements at the Orleans Transmission Station in the Ottawa area in 2015 and the Hanmer Transmission Station in the Sudbury area in 2016. We will continue to make investments required to connect new load and DG customers, as well as investments to ensure the system is capable of supplying customer needs. During 2015 and 2016, a number of our projects will address local load growth issues. Generation connection investments, consisting of OPA-contracted FIT and MicroFIT Program generators, will decrease as the volume of connections is expected to decrease.

The ADS Project continues to pilot various technologies and related capital investments and will begin to decrease in 2015 and 2016. Pilot technologies include improvements to outage response management through more effective resource dispatch, automation to isolate faults where needed, and the dynamic regulation of voltage to reduce power losses.

Off-Balance Sheet Arrangements

There are no off-balance sheet arrangements that have, or are reasonably likely to have, a material current or future effect on our financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources.

Summary of Contractual Obligations and Other Commercial Commitments

The following table presents a summary of our debt and other major contractual obligations, as well as other major commercial commitments:

December 31, 2014 (millions of Canadian dollars)	**Total**	**Less than 1 year**	**1–3 years**	**3–5 years**	**More than 5 years**
Contractual obligations *(due by year)*					
Long-term debt – principal repayments[1]	8,923	550	1,100	978	6,295
Long-term debt – interest payments[1]	7,765	419	774	677	5,895
Pension[2]	361	174	187	–	–
Environmental and asset retirement obligations[3]	284	19	73	68	124
Outsourcing agreements[4]	701	179	291	218	13
Operating lease commitments	45	7	19	10	9
Total contractual obligations	18,079	1,348	2,444	1,951	12,336
Other commercial commitments *(by year of expiry)*					
Bank line[5]	1,500	–	–	1,500	–
Letters of credit[6]	134	134	–	–	–
Guarantees[6]	331	331	–	–	–
Total other commercial commitments	1,965	465	–	1,500	–

[1] The "long-term debt – principal repayments" amounts are not charged to our results of operations, but are reflected on our Consolidated Balance Sheets and Consolidated Statements of Cash Flows. Interest associated with the long-term debt is recorded in financing charges on our Consolidated Statements of Operations and Comprehensive Income or as a cost of our capital programs.

[2] Contributions to the Hydro One Pension Fund were generally made one month in arrears. However, due to the interest rate environment, the annual contributions have been prepaid in each of the last two years. No contribution prepayments are anticipated in 2015. The 2015 and 2016 minimum pension contributions are based on an actuarial valuation as at December 31, 2013. Pension contributions totalling $174 million were made during the year ended December 31, 2014. Minimum pension contributions beyond 2016 will be based on an actuarial valuation effective no later than December 31, 2016, and will depend on future investment returns, changes in benefits, or actuarial assumptions. Pension contributions beyond 2016 are not estimable at this time.

[3] We record a liability for the estimated future expenditures associated with the removal and destruction of PCB-contaminated insulating oils and related electrical equipment, and for the assessment and remediation of chemically-contaminated lands. We also record a liability for asset retirement obligations associated with the removal and disposal of asbestos-containing materials installed in some of our facilities, as well as the future decommissioning and removal of two of our switching stations. The forecasted expenditure pattern reflects our planned work programs for the periods.

[4] In 2014, we have finalized a new outsourcing agreement with Inergi for the provision of certain services, as well as a facilities outsourcing agreement with Brookfield. Details of the new outsourcing agreements can be found in the section "New Developments in 2014 – Other – Outsourcing Agreements." Based on the September 2013 Shareholder Resolution, the Province requires us to contract only with parties who are employed and physically located in Ontario when providing services to our company. The contractual amounts disclosed include an estimated contractual annual inflation adjustment in the range of 1.9% to 2.1%. Payments in respect of our outsourcing agreements are recorded in operation, maintenance and administration costs on our Consolidated Statements of Operations and Comprehensive Income or as a cost of our capital programs.

[5] In support of our liquidity requirements, we have a $1,500 million revolving standby credit facility with a syndicate of banks maturing in June 2019.

[6] We currently have outstanding bank letters of credit of $126 million relating to retirement compensation arrangements. We provide prudential support to the IESO in the form of letters of credit, the amount of which is calculated based on forecasted monthly power consumption. At December 31, 2014, we have provided a letter of credit to the IESO in the amount of $8 million to meet our current prudential requirement. We have also provided prudential support to the IESO on behalf of our subsidiaries as required by the IESO's Market Rules, using parental guarantees of $330 million, and on behalf of two distributors using total guarantees of $1 million.

RELATED PARTY TRANSACTIONS

We are owned by the Province. The Ontario Electricity Financial Corporation (OEFC), IESO, OPA, OPG, and the OEB are related parties to our company because they are controlled or significantly influenced by the Province. The following is a summary of our related party transactions during the year ended December 31, 2014:

The Province

- During 2014, we paid dividends to the Province totalling $287 million, compared to $218 million paid in 2013.
- In November 2014, we redeemed the $250 million Province of Ontario Floating-Rate Notes held as a long-term investment. These notes were originally purchased in January 2010 with a maturity date of November 19, 2014.

IESO

- During 2014, we purchased power in the amount of $2,601 million from the IESO-administered electricity market, compared to $2,477 million purchased in 2013.
- We receive revenues for transmission services from the IESO, based on OEB-approved UTRs. Our 2014 transmission revenues include $1,556 million related to these services, compared to $1,509 million in 2013.
- We receive amounts for rural rate protection from the IESO. Our 2014 distribution revenues include $127 million related to this program, compared to $127 million in 2013.
- We receive revenues related to the supply of electricity to remote northern communities from the IESO. Our 2014 distribution revenues include $32 million related to these services, compared to $33 million in 2013.

OPA

- The OPA funds substantially all of our CDM programs. The funding includes program costs, incentives, and management fees. During 2014, we received $33 million from the OPA related to these programs, compared to $34 million received in 2013.

OPG

- During 2014, we purchased power in the amount of $23 million from OPG, compared to $15 million in 2013.
- Our company has service level agreements with OPG. These services include field, engineering, logistics and telecommunications services. Our 2014 other revenues include $12 million related to these service level agreements, compared to $9 million in 2013. Our 2014 operation, maintenance and administration costs related to the purchase of services with respect to these service level contracts were $1 million, compared to $1 million in 2013.

OEFC

- During 2014, we made payments in lieu of corporate income taxes to the OEFC totalling $86 million, compared to payments of $138 million made in 2013.
- During 2014, we purchased power in the amount of $9 million from power contracts administered by the OEFC, compared to $8 million purchased in 2013.
- During 2014, our company paid a $5 million annual fee to the OEFC, compared to $5 million paid in 2013, for indemnification against adverse claims in excess of $10 million paid by the OEFC with respect to certain of Ontario Hydro's businesses transferred to Hydro One on April 1, 1999.

OEB

- Under the *OEB Act*, the OEB is required to recover all of its annual operating costs from gas and electricity distributors and transmitters. During 2014, we incurred $12 million in OEB fees, compared to $12 million incurred in 2013.

At December 31, 2014, the amounts due from and due to related parties as a result of the transactions described above were $224 million and $227 million, respectively, compared to $197 million and $230 million at December 31, 2013, respectively. At December 31, 2014, included in amounts due to related parties were amounts owing to the IESO in respect of power purchases of $214 million, compared to $217 million at December 31, 2013.

CONSIDERATIONS OF CURRENT ECONOMIC CONDITIONS

Effect of Load on Revenue

Our load, based on normal weather patterns, is expected to increase in 2015 due to economic growth in all sectors of the Ontario economy, partially offset by the load impact of CDM and embedded generation. Overall load growth due to the economy alone is forecasted to be approximately 1.9%, with the commercial and industrial sectors slightly outperforming the residential sector. The load impacts of CDM and embedded generation are expected to have a negative impact on load growth of approximately 0.6% and 0.4%, respectively. On the whole, our load is expected to increase by approximately 0.9% in 2015. Our approved revenue requirement for 2015 has taken the negative load impact of CDM and embedded generation into account. A load growth below our load forecast, included in our approved revenue requirement, would negatively impact our financial results.

Effect of Interest Rates

Changes in interest rates will impact the calculation of the revenue requirements upon which our rates are based. The first component impacted by interest rates is our return on equity (ROE). The OEB-approved adjustment formula for calculating ROE will increase or decrease by 50% of the change between the current Long Canada Bond Forecast and the risk-free rate established at 4.25% and 50% of the change in the spread in 30-year "A"-rated Canadian utility bonds over the 30-year benchmark Government of Canada bond yield established at 1.415%. All other things being equal, we estimate that a 1% decrease in the forecasted long-term Government of Canada bond yield used in determining our ROE would reduce Hydro One Networks' transmission and distribution businesses' 2015 results of operations by approximately $20 million and $13 million, respectively. As interest rates decline, there is more risk of a decline in our net income. The second component of revenue requirement that would be impacted by interest rates is the return on debt. The difference between actual interest rates on new debt issuances and those approved for return by the OEB would impact our results of operations.

Input Costs

In support of our ongoing work programs, we are required to procure materials, supplies and services. To manage our total costs, we regularly establish security of supply, strategic material and services contracts, general outline agreements, and vendor alliances and we also manage a stock of commonly used items. Such arrangements are for a defined period of time and are monitored. Where advantageous, we develop long-term contractual relationships with suppliers to optimize the cost of goods and services and to ensure the availability and timely supply of critical items. As a result of our strategic sourcing practices, we do not foresee any adverse impacts on our business from current economic conditions in respect of adequacy and timing of supply and credit risk of our counterparties. Further, we have been able to realize significant savings through our strategic sourcing initiatives.

During 2014, we finalized a new outsourcing agreement with Inergi for the provision of certain services, as well as a facilities outsourcing agreement. Details of the new outsourcing agreements can be found in the section "New Developments in 2014 – Other – Outsourcing Agreements."

Pension Plan

In 2014, we contributed approximately $174 million to our pension plan, compared to contributions of approximately $160 million made in 2013, and incurred $158 million in net periodic pension benefit costs, compared to $287 million incurred in 2013. We currently estimate our total annual pension contributions to be approximately $174 million for 2015 and $175 million for 2016, based on an actuarial valuation as at December 31, 2013 and projected levels of pensionable earnings. Actuarial valuations are required to be filed at least every three years. Future minimum contributions beyond 2016 will be based on an actuarial valuation effective no later than December 31, 2016. In 2014, our pension plan experienced positive returns of approximately 12.3%, compared to approximately 17.9% in 2013.

Our pension benefits obligation is impacted by various assumptions and estimates, such as discount rate, rate of return on plan assets, rate of cost of living increase, and mortality assumptions. A full discussion of the significant assumptions and estimates can be found in the section "Critical Accounting Estimates – Employee Future Benefits."

RISK MANAGEMENT AND RISK FACTORS

We have an Enterprise Risk Management (ERM) Program that aims at balancing business risks and returns. A company-wide approach enables regulatory, strategic, operational and financial risks to be managed and aligned with our strategic goals. Our ERM program helps us to better understand uncertainty and its potential impact on our strategic goals. It sets out the uniform principles, processes and criteria for identifying, assessing, evaluating, treating, monitoring and communicating risks across all lines of business. It supports our Board of Directors' corporate governance needs and the due diligence responsibilities of senior management.

While our philosophy is that risk management is the responsibility of all employees, the Board of Directors annually reviews our company's risk tolerances, risk management policies, processes and accountabilities. Twice per year, the Board of Directors reviews our risk profile, which is the list of key risks prepared by senior management, and represents the greatest threats to meeting our strategic objectives. The Board of Directors' committees review risks relevant to their mandate at every meeting. The Audit, Finance and Pension Investment Committee of our Board of Directors annually reviews the status of our internal control framework.

Our President and Chief Executive Officer (CEO) has ultimate accountability for risk management. Our Leadership Team provides senior management oversight of our risk portfolio and our risk management processes. The leadership team provides direction on the evolution of these processes and identifies priority areas of focus for risk assessment and mitigation planning.

Our Chief Financial Officer (CFO) is responsible for ensuring that the risk management program is an integral part of our business strategy, planning and objective setting. The CFO has specific accountability for ensuring that ERM processes are established, properly documented and maintained by our company.

Our senior managers, line and functional managers are responsible for managing risks within the scope of their authority and accountability. Risk acceptance or mitigation decisions are made within the risk tolerances specified by the head of the subsidiary or function.

The CFO provides support to the committees of our Board of Directors, the President and CEO, the senior management team and key managers within our company. This support includes developing risk management frameworks, policies and processes, introducing and promoting new techniques, establishing risk tolerances, preparing annual corporate risk profiles, maintaining a registry of key business risks and facilitating risk assessments across our company. Our internal audit staff is responsible for performing independent reviews of the effectiveness of risk management policies, processes and systems. Starting in 2013, our Board of Directors has taken on an enhanced role in our governance structure. Each committee of the Board of Directors will take accountability for reviewing specific risks of our company.

Key elements of our ERM Program enable us to identify, assess and monitor our risks effectively. These include having an ERM policy and framework which communicates our philosophy and process for risk management across our company. A discussion of risks is an integral part of each line of business' planning documents on an annual basis. Risk identification is also considered as part of each business case for investments. Finally, discrete risk assessments and workshops are performed for specific lines of business, key projects and various profiles, such as customer relationships and regulatory compliance. In order to drive consistency throughout our risk identification and risk management processes, we use a standard list of risk sources known as our risk universe. These sources are maintained in a single database that provides a consistent basis for risk identification and classification and serves as a repository for our risk assessments. All risk assessments in our company start with this risk universe. We also use standard risk criteria, which establish the metrics and terminology used for assessing and communicating on risks, and help ensure a consistent basis for our risk assessments and risk evaluations across all lines of business. Risk criteria include formally established risk tolerances and standard scales for assessing the probability of a risk materializing and the strength of controls in place to mitigate them.

Our key risks are as follows:

Ownership by the Province

The Province owns all of our outstanding shares. Accordingly, the Province has the power to determine the composition of our Board of Directors, appoint the Chair, and influence our major business and corporate decisions. We and the Province have entered into a memorandum of agreement relating to certain aspects of the governance of our company. Pursuant to such agreement, in September 2008, the Province made a declaration removing certain powers from our company's directors pertaining to the off-shoring of jobs under the 2001 Inergi Agreement. In 2011, the Province made a declaration preventing our company from seeking cost recovery through the regulatory process for the cost of upgrades required for either MicroFIT or Small FIT generators for costs related to investment and expenditures made. Effective September 30, 2013, the Province made a declaration regarding the outsourcing of services covered by the Inergi Agreement.

Effective December 17, 2014, the Province made a further declaration pursuant to the memorandum of agreement and section 108 of the *Business Corporations Act* (Ontario) regarding the provision of information, personnel and resources to the Premier's Advisory Council on Government Assets. By way of the declaration and concurrent Shareholder resolution, the Province restricted the rights, powers and duties of our Board of Directors, and at the same time assumed such rights, powers and duties, with respect to providing the Premier's Advisory Council on Government Assets, the Government or the Ministries and their advisors and consultants all information, assistance, personnel, resources and reports as and when requested and co-operating with those Government advisors tasked with providing recommendations on labour relations matters and pension-related matters. The directors are charged with carrying out the intention of the declaration and resolution, including taking such necessary steps to issue similar declarations and resolutions with respect to Hydro One Networks and Hydro One Brampton Networks. The Province could mandate the selling of all or part of our distribution business and this could have a material adverse effect on our company.

In 2009, the Province required our company, among other entities, to adhere to certain accountability measures regarding consulting contracts and employee travel, meal and hospitality expenses. The Province may require us to adhere to further accountability measures or may make similar declarations in the future, some of which may have a material adverse effect on our business. Our company's credit ratings may change with the credit ratings of the Province, to the extent the credit rating agencies link the two ratings by virtue of our company's ownership by the Province.

Conflicts of interest may arise between us and the Province as a result of the obligation of the Province to act in the best interests of the residents of Ontario in a broad range of matters, including the regulation of Ontario's electricity industry and environmental matters, any future sale or other transaction by the Province with respect to its ownership interest in our company, including any potential outcomes arising out of the recommendations of the Ontario Distribution Sector Review Panel's report, the Province's ownership of OPG, and the determination of the amount of dividend or proxy tax payments. We may not be able to resolve any potential conflict with the Province on terms satisfactory to us, which could have a material adverse effect on our business.

Regulatory Risk

We are subject to regulatory risks, including the approval by the OEB of rates for our Transmission and Distribution Businesses that permit a reasonable opportunity to recover the estimated costs of providing safe and reliable service on a timely basis and earn the approved rates of return.

The OEB approves our transmission and distribution rates based on projected electricity load and consumption levels. If actual load or consumption materially falls below projected levels, our net income for either, or both, of these businesses could be materially adversely affected. Also, our current revenue requirements for these businesses are based on cost assumptions that may not materialize. There is no assurance that the OEB would allow rate increases sufficient to offset unfavourable financial impacts from unanticipated changes in electricity demand or in our costs.

The OEB's new RRFE requires that the term of a custom rate application (distribution business) be a five-year period. There are risks associated with forecasting over a longer period. Changes in the industry may alter the investment needs or require changes to rate setting that could result in a significant impact on our company's capability to execute its plan.

Our load could also be negatively affected by successful CDM programs. We are also subject to risk of revenue loss from other factors, such as economic trends and weather.

We expect to make investments in the coming years to connect new renewable generating stations. There is the possibility that we could incur unexpected capital expenditures to maintain or improve our assets, particularly given that new technology is required to support renewable generation, and unforeseen technical issues may be identified through implementation of projects. The risk exists that the OEB may not allow full recovery of such investments in the future. To the extent possible, we aim to mitigate this risk by ensuring prudent expenditures, seeking from the regulator clear policy direction on cost responsibility, and pre-approval of the need for capital expenditures.

While we expect all of our expenditures to be fully recoverable after OEB review, any future regulatory decision to disallow or limit the recovery of such costs would lead to potential asset impairment and charges to our results of operations, which could have a material adverse effect on our company.

In Ontario, the Market Rules mandate that we comply with the reliability standards established by NERC and NPCC. As a result, we will be required to comply with the United States Federal Energy Regulatory Commission's definition of Bulk Electric System unless we are granted an exception which will allow the application of the new definition in a cost-effective manner. Our company plans to submit exception applications and will look for recovery of costs incurred in meeting the definition in our rates; however, an adverse decision on an exception of recovery of costs could have an adverse effect on our company.

Risk of Natural and Other Unexpected Occurrences

Our facilities are exposed to the effects of severe weather conditions, natural disasters, man-made events including cyber and physical terrorist type attacks and, potentially, catastrophic events, such as a major accident or incident at a facility of a third party (such as a generating plant) to which our transmission or distribution assets are connected. Although constructed, operated and maintained to industry standards, our facilities may not withstand occurrences of this type in all circumstances. We do not have insurance for damage to our transmission and distribution wires, poles and towers located outside our transmission and distribution stations resulting from these events. Losses from lost revenues and repair costs could be substantial, especially for many of our facilities that are located in remote areas. We could also be subject to claims for damages caused by our failure to transmit or distribute electricity. Our risk is partly mitigated because our transmission system is designed and operated to withstand the loss of any major element and possesses inherent redundancy that provides alternate means to deliver large amounts of power. In the event of a large uninsured loss we would apply to the OEB for recovery of such loss; however, there can be no assurance that the OEB would approve any such applications, in whole or in part, which could have a material adverse effect on our net income.

First Nations and Métis Claims Risk

Some of our current and proposed transmission and distribution lines may traverse lands over which First Nations and Métis have Aboriginal, treaty or other legal claims. Although we have a recent history of successful negotiations, engagement and consultation with First Nations and Métis communities in Ontario, some communities and/or their citizens have expressed an increasing willingness to assert their claims through the courts, tribunals, or by direct action, which in turn can affect business activities. As a result, there exists uncertainty relating to business operations and project planning which could have an adverse effect on our company.

Risk from Transfer of Assets Located on Reserves

The transfer orders by which we acquired certain of Ontario Hydro's businesses as of April 1, 1999, did not transfer title to some assets located on Reserves. Currently, OEFC holds legal title to these assets and we manage them until we have obtained necessary authorizations to complete the title transfer. To occupy Reserves, our company must have valid permits issued by Her Majesty the Queen in the Right of Canada. For each permit, we must negotiate an agreement (in the form of a Memorandum of Understanding) with the First Nation, OEFC and any members of the First Nation who have occupancy rights. The agreement includes provisions whereby the First Nation consents to the federal Department of Aboriginal Affairs and Northern Development issuing a permit. Where the agreement and permit are for transmission assets, our company must negotiate terms of payment. It is difficult to predict the aggregate amount that we may have to pay, either on an annual or one-time basis, to obtain the required agreements from First Nations. In 2014, we paid approximately $1 million to First Nations in respect of these agreements. OEFC will continue to hold these assets until we are able to negotiate agreements with First Nations and occupants. If we cannot reach satisfactory agreements and obtain federal permits, we may have to relocate these assets to other locations at a cost that could be substantial. In a limited number of cases, it may be necessary to abandon a line and replace it with diesel-generation facilities. In either case, the costs relating to these assets could have a material adverse effect on our net income if we are not able to recover them in future rate orders.

Risk Associated with Information Technology Infrastructure

Our ability to operate effectively in the Ontario electricity market is in part dependent upon us developing, maintaining and managing complex information technology systems which are employed to operate our transmission and distribution facilities, financial and billing systems, and business systems. Our increasing reliance on information systems and expanding data networks increases our exposure to information security threats. We mitigate this risk through various methods including the use of security event management tools on our power and business systems, by separating our power system network from our business system network, by performing scans of our systems for known cyber threats, and by providing company-wide awareness training to our personnel. We also engage the services of external experts to evaluate the security of our IT infrastructure and controls. We perform vulnerability assessments on our critical cyber assets and we ensure security and privacy controls are incorporated into new IT capabilities. Although these security and system disaster recovery controls are in place, there can be no guarantee that there will not be system failures or security breaches. Upon occurrence, the focus would shift from prevention to isolation, remediation and recovery until the incident has been fully addressed. Any such system failures or security breaches could have a material adverse effect on our company.

Workforce Demographic Risk

By the end of 2014, approximately 17% of our employees were eligible for retirement and by the end of 2015 up to 21% could be eligible. These percentages are not evenly spread across our workforce, but tend naturally to be most significant in the most senior levels of our staff and especially among management and executive staff. Accordingly our continued success will be tied to our ability to attract and retain sufficient qualified staff to replace the capability lost through retirements and meet the demands of our work programs. This will be more challenging than in the past for a number of reasons.

Firstly, we expect the skilled labour market for our industry to be highly competitive in the future: many of our current employees and many of the employees we are going to be looking for possess skills and experience that will also be highly sought after by other organizations inside and outside the electricity sector; secondly, a variety of restraints on compensation and benefits for management and executive staff (including Bill 8) together with possible pension plan changes, and the uncertainty attaching to Hydro One's future size and scope as a result of the work of the Council, may adversely impact our ability to attract and retain the number and calibre of people we need in these roles.

In order to mitigate the potential effects of these factors, we are focused on earlier identification and more rapid development of staff who demonstrate the potential to progress quickly, especially those who demonstrate leadership potential, and on maintaining robust but flexible succession plans for the organization. In addition we continue to advance our apprenticeship and technical training programs to ensure that our future operational staffing needs will be met.

Labour Relations Risk

The substantial majority of our employees are represented by either the Power Workers' Union (PWU) or the Society of Energy Professionals (Society). Over the past several years, significant effort has been expended to increase our flexibility to conduct operations in a more cost-efficient manner. Although we have achieved improved flexibility in our collective agreements, including a reduction in pension benefits for Society staff hired after November 2005 similar to a previous reduction affecting management staff and increased pension contributions for PWU and Society staff, we may not be able to achieve further improvement. The existing collective agreement with the PWU will expire on March 31, 2015, and the existing Society collective agreement will expire on March 31, 2016. We face financial risks related to our ability to negotiate collective agreements consistent with our rate orders. In addition, in the event of a labour dispute, we could face operational risk related to continued compliance with our licence requirements of providing service to customers. Any of these could have a material adverse effect on our company.

Risk Associated with Arranging Debt Financing

We expect to borrow to repay our existing indebtedness and fund a portion of capital expenditures. We have substantial amounts of existing debt, including $550 million maturing in 2015 and $500 million maturing in 2016. We plan to incur capital expenditures of approximately $1,600 million in 2015 and $1,625 million in 2016. Cash generated from operations, after the payment of expected dividends, will not be sufficient to fund the repayment of our existing indebtedness and capital expenditures. Our ability to arrange sufficient and cost-effective debt financing could be materially adversely affected by numerous factors, including the regulatory environment in Ontario, our results of operations and financial position, market conditions, the ratings assigned to our debt securities by credit rating agencies, and general economic conditions. Any failure or inability on our part to borrow substantial amounts of debt on satisfactory terms could impair our ability to repay maturing debt, fund capital expenditures, and meet other obligations and requirements and, as a result, could have a material adverse effect on our company.

Asset Condition

We continually monitor the condition of our assets to determine need and timing of preventative or remedial actions to maintain the desired level of service. Condition assessment is one of the key drivers for asset maintenance, refurbishment or replacement strategies to maintain equipment performance and provide reliable service quality. Our capital programs have been increasing to maintain the performance of our aging asset base. Execution of these plans is partially dependent on external factors, such as outage planning with the IESO and transmission-connected customers, funding approval by the OEB, and supply chain availability for equipment suppliers and consulting services. In addition, opportunities to remove equipment from service to accommodate construction and maintenance are becoming increasingly limited due to customer and generator priorities.

Adjustments to accommodate these external dependencies have been made in our planning process, and we are focused on overcoming these challenges to execute our work programs. However, if we are unable to carry out these plans in a timely and optimal manner, equipment performance will degrade which may compromise the reliability of the provincial grid, our ability to deliver sufficient electricity and/or customer supply security and increase the costs of operating and maintaining these assets. This could have a material adverse effect on our company.

Environmental Risk

Our health, safety and environmental management system is designed to ensure hazards and risks are identified and assessed, and controls are implemented to mitigate significant risks. This system includes a standing committee of our Board of Directors that has governance over environmental matters. However, given the territory that our system encompasses and the amount of equipment that we own, we cannot guarantee that all such risks will be identified and mitigated without significant cost and expense to our company. The following are some of the areas that may have a significant impact on our operations.

We are subject to extensive Canadian federal, provincial and municipal environmental regulation. Failure to comply could subject us to fines and other penalties. In addition, the presence or release of hazardous or other harmful substances could lead to claims by third parties and/or governmental orders requiring us to take specific actions such as investigating, controlling and remediating the effects of these substances. We are currently undertaking a voluntary LAR program covering most of our stations and service centres. This program involves the systematic identification of any contamination at or from these facilities, and, where necessary, the development of remediation plans for our company and adjacent private properties. Any contamination of our properties could limit our ability to sell these assets in the future.

We record a liability for our best estimate of the present value of the future expenditures required to comply with Environment Canada's PCB regulations and for the present value of the future expenditures to complete our LAR program. The future expenditures required to discharge our PCB obligation are expected to be incurred over the period ending 2025, while our LAR expenditures are expected to be incurred over the period ending 2022. Actual future environmental expenditures may vary materially from the estimates used in the calculation of the environmental liabilities on our balance sheet. We do not have insurance coverage for these environmental expenditures.

Under applicable regulations, we expect to incur future expenditures to identify, remove and dispose of asbestos-containing materials installed in some of our facilities. We record an asset retirement obligation for the present value of the estimated future expenditures. The estimates are based on an external, expert study of the current expenditures associated with removing such materials from our facilities. Actual future expenditures may vary materially from the estimates used for the amount of the asset retirement obligation.

There is also risk associated with obtaining governmental approvals, permits, or renewals of existing approvals and permits related to constructing or operating facilities. This may require environmental assessment or result in the imposition of conditions, or both, which could result in delays and cost increases.

We anticipate that all of our future environmental expenditures will continue to be recoverable in future electricity rates. However, any future regulatory decision to disallow or limit the recovery of such costs could have a material adverse effect on our company.

Scientists and public health experts have been studying the possibility that exposure to electric and magnetic fields emanating from power lines and other electric sources may cause health problems. If it were to be concluded that electric and magnetic fields present a health risk, or governments decide to implement exposure limits, we could face litigation, be required to take costly mitigation measures such as relocating some of our facilities or experience difficulties in locating and building new facilities. Any of these could have a material adverse effect on our company.

Pension Plan Risk

We have a defined benefit registered pension plan for the majority of our employees. Contributions to the pension plan are established by actuarial valuations which are minimally required to be filed with the Financial Services Commission of Ontario on a triennial basis. The most recently filed valuation was prepared as at December 31, 2013, and was filed in June 2014. Our company contributed approximately $160 million in respect of 2013 and approximately $174 million in respect of 2014 to its pension plan to satisfy minimum funding requirements. Contributions beyond 2014 will depend on investment returns, changes in benefits and actuarial assumptions and may include additional voluntary contributions from time to time. Nevertheless, future contributions are expected to be significant. A determination by the OEB that some of our pension expenditures are not recoverable from customers could have a material adverse effect on our company, and this risk may be exacerbated as the quantum of required pension contributions increase.

Risk Associated with Outsourcing Arrangement

Consistent with our strategy of reducing operating costs, we entered into outsourcing arrangements with Inergi and Brookfield. Details of the new outsourcing agreements can be found in the section "New Developments in 2014 – Other – Outsourcing Agreements." If either of these outsourcing agreements are terminated for any reason or expire before a new supplier is selected, we could be required to incur significant expenses to transfer to another service provider or insource, which could have a material adverse effect on our business, operating results, financial condition or prospects.

Market and Credit Risk

Market risk refers primarily to the risk of loss that results from changes in commodity prices, foreign exchange rates and interest rates. We do not have commodity price risk. We do have foreign exchange risk as we enter into agreements to purchase materials and equipment associated with our capital programs and projects that are settled in foreign currencies. This foreign exchange risk is not material. We could in the future decide to issue foreign currency-denominated debt which we would anticipate hedging back to Canadian dollars, consistent with our company's risk management policy. We are exposed to fluctuations in interest rates as our regulated rate of return is derived using a formulaic approach.

The OEB-approved adjustment formula for calculating ROE in a deemed regulatory capital structure of 40% common equity and 60% debt will increase or decrease by 50% of the change between the current Long Canada Bond Forecast and the risk-free rate established at 4.25% and 50% of the change in the spread in 30-year "A"-rated Canadian utility bonds over the 30-year benchmark Government of Canada bond yield established at 1.415%. We estimate that a 1% decrease in the forecasted long-term Government of Canada bond yield used in determining our rate of return would reduce our Transmission Business' 2015 net income by approximately $20 million and our Hydro One Networks' distribution business' 2015 net income by approximately $13 million. Our net income is adversely impacted by rising interest rates as our maturing long-term debt is refinanced at market rates. We periodically utilize interest rate swap agreements to mitigate elements of interest rate risk.

Financial assets create a risk that a counterparty will fail to discharge an obligation, causing a financial loss. Derivative financial instruments result in exposure to credit risk, since there is a risk of counterparty default. We monitor and minimize credit risk through various techniques, including dealing with highly-rated counterparties, limiting total exposure levels with individual counterparties, and by entering into master agreements which enable net settlement and by monitoring the financial condition of counterparties. We do not trade in any energy derivatives. We do, however, have interest rate swap contracts outstanding from time to time. Currently, there are no significant concentrations of credit risk with respect to any class of financial assets. We are required to procure electricity on behalf of competitive retailers and embedded LDCs for resale to their customers. The resulting concentrations of credit risk are mitigated through the use of various security arrangements, including letters of credit, which are incorporated into our service agreements with these retailers in accordance with the OEB's Retail Settlement Code. The failure to properly manage these risks could have a material adverse effect on our company.

Risk Associated with Transmission Projects

Transmission projects involve either modifying existing or building new transmission lines and/or stations or both. Such projects are required primarily to address limitations on the transmission network to transfer power from generation sources to load centres, improve regional load supply capacity and reliability, connect new generators and load customers, and to meet new, or changes to, codes and standards.

In many cases, transmission investments are contingent upon one or more of the following approvals and/or processes: *Environmental Assessment Act* (Ontario) approval(s); receipt of OEB approvals which can include expropriation; and appropriate consultation processes with First Nations and Métis communities. Obtaining OEB and/or *Environmental Assessment Act* (Ontario) approvals and carrying out these processes may also be impacted by opposition to the proposed site of transmission investments which could adversely affect transmission reliability and/or our service quality, both of which could have a material adverse effect on our company.

With the introduction on August 26, 2010, of the OEB's competitive transmission project development planning process, in the absence of a government directive, all interested transmitters will be required to submit a bid to the OEB for possibly some identified enabler facilities and network enhancement projects. The facilitation of competitive transmission could impact our future work program and our ability to expand our current transmission footprint. In addition, as bid costs are recoverable only by the successful proponent, additional costs for unsuccessful bids would be absorbed. This could have a material adverse effect on our company.

Risk from Provincial Ownership of Transmission Corridors

Pursuant to the *Reliable Energy and Consumer Protection Act, 2002*, the Province acquired ownership of our transmission corridor lands underlying our transmission system. Although we have the statutory right to use the transmission corridors, we may be limited in our ability to expand our systems. Also, other uses of the transmission corridors by third parties in conjunction with the operation of our systems may increase safety or environmental risks, which could have an adverse effect on our company.

CRITICAL ACCOUNTING ESTIMATES

The preparation of our Consolidated Financial Statements requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and costs, and related disclosures of contingencies. We base our estimates and judgments on historical experience, current conditions and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities, as well as identifying and assessing our accounting treatment with respect to commitments and contingencies. Actual results may differ from these estimates and judgments. We have identified the following critical accounting estimates used in the preparation of our Consolidated Financial Statements:

Revenues

Our monthly distribution revenue is estimated based on wholesale electricity purchases. At the end of each month, the electricity delivered to customers, but not billed, is estimated and revenue is recognized. The newly implemented CIS phase of our entity-wide system improvement project will allow us to use historical trends at a customer level to better estimate our unbilled revenue each period. This change in methodology for estimating revenue is anticipated to be implemented in 2015. Any changes in estimate will be accounted for prospectively.

Allowance for Doubtful Accounts

The allowance for doubtful accounts reflects management's best estimate of losses on billed accounts receivable balances. The allowance is based on accounts receivable aging, historical experience and other currently available information. The allowance for doubtful accounts on customer receivables is estimated by applying internally developed loss rates to the outstanding receivable balances by risk segment. Risk segments represent groups of customers with similar credit quality indicators and are computed based on various attributes, including number of days receivables are past due, delinquency of balances and payment history. Loss rates applied to the accounts receivable balances are based on historical average write-offs as a percentage of accounts receivable in each risk segment.

Regulatory Assets and Liabilities

Our regulatory assets represent certain amounts receivable from future electricity customers and costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. Our regulatory assets mainly include costs related to the pension benefit liability, deferred income tax liabilities, post-retirement and post-employment benefit liability, and environmental liabilities. Our regulatory liabilities represent certain amounts that are refundable to future electricity customers, and pertain primarily to OEB deferral and variance accounts. The regulatory assets and liabilities can be recognized for rate-setting and financial reporting purposes only if the amounts have been approved for inclusion in the electricity rates by the OEB, or if such approval is judged to be probable by management. If management judges that it is no longer probable that the OEB will allow the inclusion of a regulatory asset or liability in future electricity rates, the applicable carrying amount of the regulatory asset or liability will be reflected in results of operations in the period that the judgment is made by management.

Environmental Liabilities

We record a liability for the estimated future expenditures associated with the removal and destruction of PCB-contaminated insulating oils and related electrical equipment, and for the assessment and remediation of chemically-contaminated lands.

There are uncertainties in estimating future environmental costs due to potential external events such as changes in legislation or regulations and advances in remediation technologies. In determining the amounts to be recorded as environmental liabilities, the Company estimates the current cost of completing required work and makes assumptions as to when the future expenditures will actually be incurred, in order to generate future cash flow information. All factors used in estimating the Company's environmental liabilities represent management's best estimates of the present value of costs required to meet existing legislation or regulations. However, it is reasonably possible that numbers or volumes of contaminated assets, cost estimates to perform work, inflation assumptions and the assumed pattern of annual cash flows may differ significantly from the Company's current assumptions. Environmental liabilities are reviewed annually or more frequently if significant changes in regulations or other relevant factors occur. Estimate changes are accounted for prospectively.

In April 2014, Environment Canada enacted amendments to the existing PCB regulations, which included the extension of the end-of-use deadline from 2014 to 2025 for equipment containing certain concentrations of PCBs. Further discussion of the PCB amendments and related impact on our company can be found in the section "New Developments in 2014 – Other – Environment Canada Regulations."

Employee Future Benefits

Our employee future benefits consist of pension and post-retirement and post-employment plans, and include pension, group life insurance, health care, and long-term disability benefits provided to our current and retired employees. Employee future benefits costs are included in our labour costs that are either charged to results of operations or capitalized as part of the cost of property, plant and equipment and intangible assets. Changes in assumptions affect the benefit obligation of the employee future benefits and the amounts that will be charged to our results of operations or capitalized in future years. The following significant assumptions and estimates are used to determine employee future benefit costs and obligations:

Weighted Average Discount Rate

The weighted average discount rate used to calculate the employee future benefits obligation is determined at each year end by referring to the most recently available market interest rates based on "AA"-rated corporate bond yields reflecting the duration of the applicable employee future benefit plan. The discount rate at December 31, 2014 decreased to 4.00% from 4.75% used at December 31, 2013, in conjunction with decreases in bond yields over this period. The decrease in the discount rate has resulted in a corresponding increase in employee future benefits liabilities for accounting purposes. The liabilities are determined by independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect management's best estimates.

Expected Rate of Return on Plan Assets

The expected rate of return on pension plan assets is based on expectations of long-term rates of return at the beginning of the year and reflects a pension asset mix consistent with the pension plan's current investment policy.

Rates of return on the respective portfolios are determined with reference to respective published market indices. The expected rate of return on pension plan assets reflects our long-term expectations. We believe that this assumption is reasonable because, with the pension plan's balanced investment approach, the higher volatility of equity investment returns is intended to be offset by the greater stability of fixed-income and short-term investment returns. The net result, on a long-term basis, is a lower return than might be expected by investing in equities alone. In the short term, the pension plan can experience fluctuations in actual rates of return.

Rate of Cost of Living Increase

The rate of cost of living increase is determined by considering differences between long-term Government of Canada nominal bonds and real return bonds, which decreased from 2.00% per annum as at December 31, 2013 to approximately 1.70% per annum as at December 31, 2014. Given the Bank of Canada's commitment to keep long-term inflation between 1.00% and 3.00%, management believes that the current rate is reasonable to use as a long-term assumption and as such, has used a 2.0% per annum inflation rate for employee future benefits liability valuation purposes as at December 31, 2014.

Mortality Assumptions

Our employee future benefits liability is also impacted by changes in life expectancies used in mortality assumptions. Increases in life expectancies of plan members result in increases in the employee future benefits liability. The mortality assumption at December 31, 2014 was updated to the final tables issued by the Canadian Institute of Actuaries (for public sector, with projection scale CPM-B and no adjustment due to pension size). As at December 31, 2013, the draft tables published by the Canadian Institute of Actuaries were used.

Rate of Increase in Health Care Cost Trends

The costs of post-retirement and post-employment benefits are determined at the beginning of the year and are based on assumptions for expected claims experience and future health care cost inflation. A 1% increase in the health care cost trends would result in a $23 million increase in 2014 interest cost plus service cost, and a $248 million increase in the year-end 2014 benefit liability.

Asset Impairment

Within our regulated businesses, the carrying costs of most of our long-lived assets are included in the rate base where they earn an OEB-approved rate of return. Asset carrying values and the related return are recovered through OEB-approved rates. As a result, such assets are only tested for impairment in the event that the OEB disallows recovery, in whole or in part, or if such a disallowance is judged to be probable. We regularly monitor the assets of our unregulated Hydro One Telecom subsidiary for indications of impairment. As at December 31, 2014, no asset impairment had been recorded for assets within our regulated or unregulated businesses.

Goodwill represents the cost of acquired LDCs that is in excess of the fair value of the net identifiable assets acquired at the acquisition date. Goodwill is evaluated for impairment on an annual basis, or more frequently if circumstances require. We have concluded that goodwill was not impaired at December 31, 2014.

DISCLOSURE CONTROLS AND INTERNAL CONTROLS OVER FINANCIAL REPORTING

Internal controls have been documented and tested for adequacy and effectiveness, and continue to be refined over all business processes.

In compliance with the requirements of National Instrument 52-109, our Certifying Officers have reviewed and certified the Consolidated Financial Statements for the year ended December 31, 2014, together with other financial information included in our securities filings. Our Certifying Officers have also certified that disclosure controls and procedures (DC&P) have been designed to provide reasonable assurance that material information relating to our company is made known within our company. Further, our Certifying Officers have certified that internal controls over financial reporting (ICFR) have been designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the Consolidated Financial Statements. Based on the evaluation of the design and operating effectiveness of our company's DC&P and ICFR, our Certifying Officers concluded that our company's DC&P and ICFR were effective as at December 31, 2014.

NEW ACCOUNTING PRONOUNCEMENTS

In May 2014, the Financial Accounting Standards Board (FASB) issued an accounting standards update that provides guidance on revenue recognition which depicts the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods and services. This update is applicable to our company for the years and interim periods beginning on January 1, 2017. We are currently assessing the impact of adoption of this accounting standards update on our consolidated financial statements.

In August 2014, the FASB issued an accounting standards update that provides guidance about management's responsibility to evaluate whether there is substantial doubt about an entity's ability to continue as a going concern and related disclosures. This update is applicable to our company for the year ending December 31, 2016, and for annual and interim periods thereafter. We do not anticipate that the adoption of this accounting standards update will have a significant impact on our consolidated financial statements.

In November 2014, the FASB issued an accounting standards update that provides guidance on accounting for hybrid financial instruments issued in the form of a share. This update is applicable to our company for the years and interim periods beginning on January 1, 2016. We are currently assessing the impact of adoption of this accounting standards update on our consolidated financial statements.

OUTLOOK

We will achieve our mission and vision and remain focused on achieving our corporate goal of providing safe, reliable and affordable service to our customers, today and tomorrow, while increasing enterprise value for our Shareholder. We will do this by continuing to concentrate on our strategic objectives of safety, customer satisfaction, continuous innovation, reliability, protection of the environment, championing people and culture, Shareholder value and productivity and cost-effectiveness. We continue to seek to strike the right balance between making prudent risk-based reliability investments and keeping customers' rates low. Effectively and efficiently managing costs is an important part of achieving this balance.

Given the nature of the work undertaken by our employees and contractors, safety remains our top priority. We will continue to focus on creating an injury-free workplace and maintaining public safety through several health and safety initiatives, including maintaining our OHSAS 18001 standing.

We are focused on becoming a customer centric company and achieving our vision of improving customer satisfaction, maintaining affordable rates for the portion of the customers' bill within our control and building a trusted partner relationship with our customers. Our plan has taken into account discussions with our customers and reflects the planned development and delivery of targeted customer segment strategies, products and services which respond to our customers' unique needs. This includes realizing value from our new CIS, simplifying and shortening timeframes for the delivery of services, enhancing accessibility in person, by phone or through our web portal and/or our mobile application to ensure effective self-service for simple transactions, and delivering programs which help customers better manage their energy consumption. In addition, to further improve our customer service performance culture as a transparent, accountable and customer-focused organization, we have recently announced two new initiatives – a third party expert Customer Service Advisory Panel and our draft Customer Commitments.

We will continue to focus on driving our transformation to a culture that is accountability-based. All of our management staff received training under our Craft of Management program. In addition, a new Talent Management program was piloted in 2014 and will be rolled out company-wide in 2015. These programs will serve as the foundation for establishing that culture of accountability. Investments in these programs, coupled with existing programs which enhance employee skills and ability, will help us deliver best-in-class service to our customers, continue the drive to zero workplace injuries and create a great workplace that will lead to improved employee engagement. We remain focused on managing the resourcing requirements of an increasing work program through appropriate compensation policies, labour negotiations, use of outsourced multi-skilled staff and support of internal and external college and university training programs. Aging workforce demographics provide opportunities, through retirements, to restructure and transform the workforce.

Our assets are in the midst of a demographic change with an increasing proportion of assets reaching the end of their expected service life and an increasing average asset age. To ensure the electricity system's reliability in the public interest, we have planned for significant investments in transmission and distribution infrastructure. Our plan includes targeted, risk-based investments to maintain, refurbish and replace existing assets that are in poor condition and beyond their expected service life, within the policy set by the OEB. Investments in technology, such as the successful implementation of Asset Analytics, have provided us with real-time asset condition and performance data, giving us the ability to make asset optimization life-cycle decisions, and opportunities through planning and scheduling data to improve materials procurement and to deploy work crews to better manage work programs to meet customer needs.

The actual timing and expenditures in our business plan are predicated on obtaining various approvals including: OEB approvals and environmental assessment approvals; successful negotiations with customers, neighbouring utilities and other stakeholders; and consultations with First Nations and Métis communities.

Over the last five years, we have replaced all of our core IT systems with a company-wide IT system. Further development of the existing IT platform will enable various tools to consistently provide a comprehensive and cascading information view of asset risks based on demographics, condition, performance, criticality, economics and utilization. In addition, we have introduced talent management, employee pay and time reporting enhancements to reduce costs, and to further develop and retain critical core competencies, skills and knowledge of our people. These new initiatives will allow us to effectively plan and reprioritize work and integrate customers' needs into multi-year investment plans. This outcome is consistent with the OEB's direction in its new Outcomes-Based Approach to regulation.

Our plan is focused on delivering integrated asset-to-work planning, optimized scheduling, and execution, as well as field mobility. Through our investment in our Workflow of the Future initiative (currently a pilot program), we will bring together data, analytics and mobility to allow our employees, especially those in the field, to do more at the job site with their mobile devices.

Significant opportunity resides with smart meters and the proliferation of ADS including energy efficiency, demand response and distributed-resource technologies over the long term. Our investments in this area will focus on reliability, customer needs and affordability. We will continue to invest on a prudent basis in the development of ADS and related grid modernization standards, customer demand work (connections and upgrades), smart meters, DG connections, including station upgrades, protection and control, new lines and some contestable work, for which we will receive customer capital contributions. There is little flexibility to reduce this work as most of it is customer demand driven.

Consistent with our corporate strategy, we will pursue an LDC consolidation approach that is robust but prudent, to facilitate the consolidation of Ontario's distribution sector. This is consistent with the Ontario Distribution Sector Review Panel's assessment that there are substantial efficiencies to be found through consolidation of Ontario LDCs and we are key to the solution. We will also work with our Shareholder to address the recommendations of the Council once they are finalized in the Council's final report which is anticipated in the spring of 2015. Our plan does not include funding for LDC acquisitions or assume any disposition of our service territory. These opportunities will be managed as they arise. Our plan also does not incorporate any projects related to competitive transmission. However, as leaders in the sector, we plan to bid on key projects. The OEB notes in its *Framework for Transmission Project Development Plans* that where projects are otherwise equivalent or close in other factors, information such as socio-economic benefits, including First Nations involvement, could prove decisive in a competitive bid. As such, First Nations involvement in competitive bids is likely to become more prevalent.

CHANGES TO OUR BOARD OF DIRECTORS

On March 7, 2014, our Shareholder, the Minister of Energy, on behalf of the Government of Ontario, announced that Sandra Pupatello would be appointed Chair of our Board of Directors, effective April 1, 2014, and on April 1, 2014, the Shareholder formally elected Ms. Pupatello as our new Chair. Ms. Pupatello is the Director of Business Development and Global Markets at PricewaterhouseCoopers Canada. She is also the Chief Executive Officer of the WindsorEssex Economic Development Corporation. Ms. Pupatello has been a member of our Board of Directors since November 2013.

On April 11, 2014, the following new members were added to our Board of Directors: William Limbrick, Tom Moss, and John Wiersma. William Limbrick was the Vice President of Information and Technology Services, Chief Information Officer of the IESO, and a Principal Consultant within the utilities practice of PricewaterhouseCoopers and Sun Life Assurance in the United Kingdom. Tom Moss is the former President and Chief Operating Officer of Telecom Ottawa, and has held strategic policy positions in the federal government at Treasury Board and Industry Canada. John Wiersma, P.Eng., is a former director of the ESA (Ontario) and IESO Board of Directors, and a former member of the Board of the Electrical and Utilities Safety Association and the Canadian Energy Efficiency Alliance.

On April 25, 2014, the following new members were added to our Board of Directors: Sally Daub, Maureen Sabia, and Carole Workman. Sally Daub is a director and former President and Chief Executive Officer of ViXS Systems, a former chair of the Small Business Agency of Ontario, and a former board member of the Information Technology Association of Canada and the Global Semiconductor Association. Maureen Sabia is the Chair of the Board of Canadian Tire Corporation Limited, and has an extensive background with organizations at the provincial and federal levels. She has been named one of Canada's Most Powerful Women and is also an officer of the Order of Canada. Carole Workman is a member of the Board of Allstate Insurance of Canada (Toronto). She also served on the Board of the Ottawa Hospital and its affiliates since 2007, and is a former member of the Board of Hydro Ottawa Holding Inc.

On April 1, 2014, James Arnett resigned from our Board of Directors. Mr. Arnett has been a member and Chair of our Board of Directors since March 2008. The Board of Directors terms for Michael Mueller, Walter Murray, Robert Pace, and Douglas Speers expired on April 11, 2014.

FORWARD-LOOKING STATEMENTS AND INFORMATION

Our oral and written public communications, including this document, often contain forward-looking statements that are based on current expectations, estimates, forecasts and projections about our business and the industry in which we operate, and include beliefs and assumptions made by the management of our company. Such statements include, but are not limited to: expectations regarding energy-related revenues and profit and their trend; statements regarding our transmission and distribution rates and customer bills resulting from our rate applications; statements related to the FIT program; statements about CDM; statements about our strategy, including our strategic objectives; statements regarding considerations of current economic conditions; statements regarding the new regional planning process; statements related to employee future benefits; expectations regarding First Nation involvement in competitive bids; statements regarding our liquidity and capital resources and operational requirements; statements about our standby credit facility; expectations regarding our financing activities; statements regarding our maturing debt; statements regarding our ongoing and planned projects and/or initiatives including the expected results of these projects and/or initiatives (including productivity savings, process improvements, and customer satisfaction) and their completion dates; expectations regarding the recoverability of large capital investments; expectations regarding generation connection investments; statements regarding expected future capital and development investments, the timing of these expenditures and our investment plans; expectations regarding OPA recommendations; statements regarding contractual obligations and other commercial commitments; statements related to the OEB; statements regarding future pension contributions, our pension plan and actuarial valuation; statements about our outsourcing arrangements with Inergi and Brookfield and such future outsourcing arrangements; statements regarding customer service performance culture, including statements about the Customer Service Advisory Panel and Customer Commitments; expectations regarding work and costs of compliance with environmental and health and safety regulations; statements related to the 2013 LTEP; statements regarding recent accounting-related guidance; statements related to the Council; statements related to the Working Group on electricity sector pension plans; statements related to B2M LP; and statements related to LDC consolidation including our acquisition of Norfolk Power, Woodstock Hydro, and Haldimand Hydro. Words such as "expect", "anticipate", "intend", "attempt", "may", "plan", "will", "believe", "seek", "estimate", "goal", "aim", "target", and variations of such words and similar expressions are intended to identify such forward-looking statements. These statements are not guarantees of future performance and involve assumptions and risks and uncertainties that are difficult to predict. Therefore, actual outcomes and results may differ materially from what is expressed, implied or forecasted in such forward-looking statements. We do not intend, and we disclaim any obligation, to update any forward-looking statements, except as required by law.

These forward-looking statements are based on a variety of factors and assumptions including, but not limited to, the following: no unforeseen changes in the legislative and operating framework for Ontario's electricity market; favourable decisions from the OEB and other regulatory bodies concerning outstanding rate and other applications; no delays in obtaining the required approvals; no unforeseen changes in rate orders or rate structures for our Distribution and Transmission Businesses; continued use of US GAAP; a stable regulatory environment; no unfavourable changes in environmental regulation; and no significant event occurring outside the ordinary course of business. These assumptions are based on information currently available to us, including information obtained from third party sources. Actual results may differ materially from those predicted by such forward-looking statements. While we do not know what impact any of these differences may have, our business, results of operations, financial condition and our credit stability may be materially adversely affected. Factors that could cause actual results or outcomes to differ materially from the results expressed or implied by forward-looking statements include, among other things:

- the risks associated with being controlled by the Province including the possibility that the Province may make declarations pursuant to the memorandum of agreement, the Province could mandate the selling of all or part of our distribution business, as well as potential conflicts of interest that may arise between us, the Province and related parties;
- the risks associated with being subject to extensive regulation including risks associated with OEB action or inaction, including regulatory decisions regarding our revenue requirements, cost recovery, rates, acquisitions and divestitures;
- the risk that previously granted regulatory approvals may be subsequently challenged, appealed or overturned;
- the risk to our facilities posed by severe weather conditions, natural disasters or catastrophic events and our limited insurance coverage for losses resulting from these events;
- public opposition to and delays or denials of the requisite approvals and accommodations for our planned projects;
- the risk that we may incur significant costs associated with transferring assets located on Reserves (as defined in the *Indian Act* (Canada));
- the risks associated with information system security, with maintaining a complex information technology system infrastructure, and with transitioning most of our financial and business processes to an integrated business and financial reporting system;
- the risks related to our workforce demographic and our potential inability to attract and retain qualified personnel;
- the ability to negotiate appropriate collective agreements;
- the risk that we are not able to arrange sufficient cost-effective financing to repay maturing debt and to fund capital investments and other obligations;
- the risks associated with the execution of our capital and operation, maintenance and administration programs necessary to maintain the performance of our aging asset base;
- the risk that future environmental expenditures are not recoverable in future electricity rates;
- the risk that the presence or release of hazardous or harmful substances could lead to claims by third parties and/or governmental orders;
- the risk that assumptions that form the basis of our recorded environmental liabilities and related regulatory assets may change;
- future interest rates, future investment returns, inflation, changes in benefits and changes in actuarial assumptions;
- the potential that we may incur significant expenses to replace some or all of the functions currently outsourced if either of our agreements with Inergi or Brookfield are terminated or expire before a new service provider is selected;
- the risks associated with changes in the forecasted long-term Government of Canada bond yield;
- the risks of counterparty default on our outstanding derivative contracts;
- the risks associated with current economic uncertainty and financial market volatility;
- the risk that our long-term credit rating would deteriorate;
- the inability to prepare financial statements using US GAAP, or IFRS, as applicable;

- the impact of the 2013 LTEP on our company and the costs and expenses arising therefrom;
- unanticipated changes in electricity demand or in our costs;
- the risk that unexpected capital investments may be needed to support renewable generation or resolve unforeseen technical issues; and
- the impact of the ownership by the Province of lands underlying our transmission system.

We caution the reader that the above list of factors is not exhaustive. Some of these and other factors are discussed in more detail in the section "Risk Management and Risk Factors" in this MD&A. You should review this section in detail.

In addition, we caution the reader that information provided in this MD&A regarding our outlook on certain matters, including potential future expenditures, is provided in order to give context to the nature of some of our future plans and may not be appropriate for other purposes.

Additional information about the Company, including the Company's Annual Information Form, can be found on SEDAR at www.sedar.com and on the US Securities and Exchange Commission's website at www.sec.gov.

MANAGEMENT'S REPORT

The Consolidated Financial Statements, Management's Discussion and Analysis (MD&A) and related financial information have been prepared by the management of Hydro One Inc. (Hydro One or the Company). Management is responsible for the integrity, consistency and reliability of all such information presented. The Consolidated Financial Statements have been prepared in accordance with United States Generally Accepted Accounting Principles and applicable securities legislation. The MD&A has been prepared in accordance with National Instrument 51-102.

The preparation of the Consolidated Financial Statements and information in the MD&A involves the use of estimates and assumptions based on management's judgment, particularly when transactions affecting the current accounting period cannot be finalized with certainty until future periods. Estimates and assumptions are based on historical experience, current conditions and various other assumptions believed to be reasonable in the circumstances, with critical analysis of the significant accounting policies followed by the Company as described in Note 2 to the Consolidated Financial Statements. The preparation of the Consolidated Financial Statements and the MD&A includes information regarding the estimated impact of future events and transactions. The MD&A also includes information regarding sources of liquidity and capital resources, operating trends, risks and uncertainties. Actual results in the future may differ materially from the present assessment of this information because future events and circumstances may not occur as expected. The Consolidated Financial Statements and MD&A have been properly prepared within reasonable limits of materiality and in light of information up to February 11, 2015.

Management is responsible for establishing and maintaining adequate internal control over financial reporting for the Company. In meeting its responsibility for the reliability of financial information, management maintains and relies on a comprehensive system of internal control and internal audit. The system of internal control includes a written corporate conduct policy; implementation of a risk management framework; effective segregation of duties and delegation of authorities; and sound and conservative accounting policies that are regularly reviewed. This structure is designed to provide reasonable assurance that assets are safeguarded and that reliable information is available on a timely basis. In addition, management has assessed the design and operating effectiveness of the Company's internal control over financial reporting in accordance with the criteria set forth in Internal Control – Integrated Framework (2013), issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management concluded that the Company maintained effective internal control over financial reporting as of December 31, 2014. The effectiveness of these internal controls is reported to the Audit, Finance and Pension Investment Committee of the Hydro One Board of Directors, as required.

The Consolidated Financial Statements have been audited by KPMG LLP, independent external auditors appointed by the Shareholder. The external auditors' responsibility is to express their opinion on whether the Consolidated Financial Statements are fairly presented in accordance with United States Generally Accepted Accounting Principles. The Independent Auditors' Report outlines the scope of their examination and their opinion.

The Hydro One Board of Directors, through its Audit, Finance and Pension Investment Committee, is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal controls. The Audit, Finance and Pension Investment Committee of Hydro One met periodically with management, the internal auditors and the external auditors to satisfy itself that each group had properly discharged its respective responsibility and to review the Consolidated Financial Statements before recommending approval by the Board of Directors. The external auditors had direct and full access to the Audit, Finance and Pension Investment Committee, with and without the presence of management, to discuss their audit findings, if any.

The President and Chief Executive Officer and the Chief Financial Officer (Acting) have certified Hydro One's annual Consolidated Financial Statements and annual MD&A, related disclosure controls and procedures and the design and effectiveness of related internal controls over financial reporting.

On behalf of Hydro One Inc.'s management:

Carmine Marcello
President and Chief Executive Officer

Ali R. Suleman
Chief Financial Officer (Acting)

INDEPENDENT AUDITORS' REPORT

To the Shareholder of Hydro One Inc.

We have audited the accompanying Consolidated Financial Statements of Hydro One Inc., which comprise the consolidated balance sheets as at December 31, 2014 and December 31, 2013, the consolidated statements of operations and comprehensive income, changes in equity and cash flows for the years then ended, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these Consolidated Financial Statements in accordance with United States Generally Accepted Accounting Principles, and for such internal control as management determines is necessary to enable the preparation of Consolidated Financial Statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these Consolidated Financial Statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the Consolidated Financial Statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the Consolidated Financial Statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the Consolidated Financial Statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the Consolidated Financial Statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the Consolidated Financial Statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the Consolidated Financial Statements present fairly, in all material respects, the consolidated financial position of Hydro One Inc. as at December 31, 2014 and December 31, 2013, and its consolidated results of operations and its consolidated cash flows for the years then ended in accordance with United States Generally Accepted Accounting Principles.

KPMG LLP

Chartered Professional Accountants, Licensed Public Accountants

Toronto, Canada
February 11, 2015

CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

For the years ended December 31, 2014 and 2013

Year ended December 31 (millions of Canadian dollars, except per share amounts)	**2014**	2013
Revenues		
Distribution (includes $159 related party revenues; 2013 – $160) *(Note 20)*	**4,903**	4,484
Transmission (includes $1,567 related party revenues; 2013 – $1,517) *(Note 20)*	**1,588**	1,529
Other	**57**	61
	6,548	6,074
Costs		
Purchased power (includes $2,633 related party costs; 2013 – $2,500) *(Note 20)*	**3,419**	3,020
Operation, maintenance and administration *(Note 20)*	**1,192**	1,106
Depreciation and amortization *(Note 5)*	**722**	676
	5,333	4,802
Income before financing charges and provision for payments in lieu of corporate income taxes	**1,215**	1,272
Financing charges *(Note 6)*	**379**	360
Income before provision for payments in lieu of corporate income taxes	**836**	912
Provision for payments in lieu of corporate income taxes *(Notes 7, 20)*	**89**	109
Net income	**747**	803
Net income (loss) attributable to noncontrolling interest *(Note 4)*	**(2)**	–
Net income attributable to the Shareholder of Hydro One Inc.	**749**	803
Other comprehensive income	**–**	–
Comprehensive income	**747**	803
Comprehensive income (loss) attributable to noncontrolling interest *(Note 4)*	**(2)**	–
Comprehensive income attributable to the Shareholder of Hydro One Inc.	**749**	803
Basic and fully diluted earnings per common share *(dollars) (Note 18)*	**7,319**	7,850
Dividends per common share declared *(dollars) (Note 19)*	**2,696**	2,000

See accompanying notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS

At December 31, 2014 and 2013

December 31 (millions of Canadian dollars)	**2014**	2013
Assets		
Current assets:		
Cash and cash equivalents *(Note 13)*	**100**	565
Accounts receivable (net of allowance for doubtful accounts – $66; 2013 – $36) *(Note 8)*	**1,016**	923
Due from related parties *(Note 20)*	**224**	197
Regulatory assets *(Note 11)*	**31**	47
Materials and supplies	**23**	23
Deferred income tax assets *(Note 7)*	**19**	18
Derivative instruments *(Note 13)*	**2**	6
Investment *(Notes 13, 20)*	**–**	251
Prepaid expenses and other assets	**35**	28
	1,450	2,058
Property, plant and equipment *(Note 9)*:		
Property, plant and equipment in service	**25,356**	23,820
Less: accumulated depreciation	**9,134**	8,615
	16,222	15,205
Construction in progress	**1,025**	1,078
Future use land, components and spares	**154**	148
	17,401	16,431
Other long-term assets:		
Regulatory assets *(Note 11)*	**3,200**	2,636
Intangible assets (net of accumulated amortization – $305; 2013 – $252) *(Note 10)*	**276**	313
Goodwill *(Note 4)*	**173**	133
Deferred debt issuance costs	**36**	36
Deferred income tax assets *(Note 7)*	**7**	11
Derivative instruments *(Note 13)*	**–**	6
Other	**7**	1
	3,699	3,136
Total assets	**22,550**	21,625

See accompanying notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS (continued)

At December 31, 2014 and 2013

December 31 (millions of Canadian dollars, except number of shares)	**2014**	2013
Liabilities		
Current liabilities:		
Bank indebtedness *(Note 13)*	**2**	31
Accounts payable	**173**	135
Accrued liabilities *(Notes 15, 16)*	**611**	654
Due to related parties *(Note 20)*	**227**	230
Accrued interest	**100**	100
Regulatory liabilities *(Note 11)*	**47**	85
Derivative instruments *(Note 13)*	**3**	–
Long-term debt payable within one year (includes $252 measured at fair value; 2013 – $506) *(Notes 12, 13)*	**552**	756
	1,715	1,991
Long-term debt (includes $nil measured at fair value; 2013 – $256) *(Notes 12, 13)*	**8,373**	8,301
Other long-term liabilities:		
Post-retirement and post-employment benefit liability *(Note 15)*	**1,533**	1,488
Deferred income tax liabilities *(Note 7)*	**1,313**	1,129
Pension benefit liability *(Note 15)*	**1,236**	845
Environmental liabilities *(Note 16)*	**221**	239
Regulatory liabilities *(Note 11)*	**168**	163
Net unamortized debt premiums	**18**	20
Asset retirement obligations *(Note 17)*	**9**	14
Long-term accounts payable and other liabilities	**17**	20
	4,515	3,918
Total liabilities	**14,603**	14,210
Contingencies and commitments (Notes 22, 23)		
Subsequent Event (Note 25)		
Preferred shares (authorized: unlimited; issued: 12,920,000) *(Notes 18, 19)*	**323**	323
Noncontrolling interest subject to redemption *(Note 4)*	**21**	–
Equity		
Common shares (authorized: unlimited; issued: 100,000) *(Notes 18, 19)*	**3,314**	3,314
Retained earnings	**4,249**	3,787
Accumulated other comprehensive loss	**(9)**	(9)
Noncontrolling interest *(Note 4)*	**49**	–
Total equity	**7,603**	7,092
	22,550	21,625

See accompanying notes to Consolidated Financial Statements.

On behalf of the Board of Directors:

George L Cooke

Sandra Pupatello
Chair

George L. Cooke
Chair, Audit, Finance and Pension Investment Committee

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

For the years ended December 31, 2014 and 2013

Year ended December 31, 2014 (millions of Canadian dollars)	**Common Shares**	**Retained Earnings**	**Accumulated Other Comprehensive Loss**	**Noncontrolling Interest**	**Total Equity**
January 1, 2014	**3,314**	**3,787**	**(9)**	**–**	**7,092**
Net income	–	**749**	–	**(1)**	**748**
Other comprehensive income	–	–	–	–	–
Amount contributed by noncontrolling interest	–	–	–	**50**	**50**
Dividends on preferred shares	–	**(18)**	–	–	**(18)**
Dividends on common shares	–	**(269)**	–	–	**(269)**
December 31, 2014	**3,314**	**4,249**	**(9)**	**(49)**	**7,603**

Year ended December 31, 2013 (millions of Canadian dollars)	Common Shares	Retained Earnings	Accumulated Other Comprehensive Loss	Noncontrolling Interest	Total Equity
January 1, 2013	3,314	3,202	(9)	–	6,507
Net income	–	803	–	–	803
Other comprehensive income	–	–	–	–	–
Dividends on preferred shares	–	(18)	–	–	(18)
Dividends on common shares	–	(200)	–	–	(200)
December 31, 2013	3,314	3,787	(9)	–	7,092

See accompanying notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the years ended December 31, 2014 and 2013

Year ended December 31 (millions of Canadian dollars)	**2014**	2013
Operating activities		
Net income	**747**	803
Environmental expenditures	**(18)**	(16)
Adjustments for non-cash items:		
Depreciation and amortization (excluding removal costs)	**641**	597
Regulatory assets and liabilities	**(69)**	3
Deferred income taxes	**10**	(2)
Other	**–**	8
Changes in non-cash balances related to operations *(Note 21)*	**(55)**	11
Net cash from operating activities	**1,256**	1,404
Financing activities		
Long-term debt issued	**628**	1,185
Long-term debt retired	**(776)**	(600)
Amount contributed by noncontrolling interest *(Note 4)*	**72**	–
Dividends paid	**(287)**	(218)
Change in bank indebtedness	**(29)**	(11)
Other	**(3)**	(5)
Net cash from (used in) financing activities	**(395)**	351
Investing activities		
Capital expenditures *(Note 21)*		
Property, plant and equipment	**(1,481)**	(1,308)
Intangible assets	**(23)**	(79)
Acquisition of Norfolk Power Inc. *(Note 4)*	**(66)**	–
Proceeds from investment	**250**	–
Other	**(6)**	2
Net cash used in investing activities	**(1,326)**	(1,385)
Net change in cash and cash equivalents	**(465)**	370
Cash and cash equivalents, beginning of year	**565**	195
Cash and cash equivalents, end of year	**100**	565

See accompanying notes to Consolidated Financial Statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

For the years ended December 31, 2014 and 2013

1. DESCRIPTION OF THE BUSINESS

Hydro One Inc. (Hydro One or the Company) was incorporated on December 1, 1998, under the *Business Corporations Act* (Ontario) and is wholly owned by the Province of Ontario (Province). The principal businesses of Hydro One are the transmission and distribution of electricity to customers within Ontario. The electricity rates of these businesses are regulated by the Ontario Energy Board (OEB).

2. SIGNIFICANT ACCOUNTING POLICIES

Basis of Consolidation

These Consolidated Financial Statements include the accounts of the Company and its wholly owned subsidiaries: Hydro One Networks Inc. (Hydro One Networks), Hydro One Remote Communities Inc. (Hydro One Remote Communities), Hydro One Brampton Networks Inc. (Hydro One Brampton Networks), Hydro One Telecom Inc. (Hydro One Telecom), Hydro One Lake Erie Link Management Inc., Hydro One Lake Erie Link Company Inc., Norfolk Power Inc. (Norfolk Power), and Hydro One B2M Holdings. Intercompany transactions and balances have been eliminated.

Basis of Accounting

These Consolidated Financial Statements are prepared and presented in accordance with United States (US) Generally Accepted Accounting Principles (GAAP) and in Canadian dollars.

Hydro One performed an evaluation of subsequent events through to February 11, 2015, the date these Consolidated Financial Statements were issued, to determine whether any events or transactions warranted recognition and disclosure in these Consolidated Financial Statements. See Note 25 – Subsequent Event.

Use of Management Estimates

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues, expenses, gains and losses during the reporting periods. Management evaluates these estimates on an ongoing basis based upon historical experience, current conditions, and assumptions believed to be reasonable at the time the assumptions are made, with any adjustments being recognized in results of operations in the period they arise. Significant estimates relate to regulatory assets and regulatory liabilities, environmental liabilities, pension benefits, post-retirement and post-employment benefits, asset retirement obligations (AROs), goodwill and asset impairments, contingencies, unbilled revenues, allowance for doubtful accounts, derivative instruments, and deferred income tax assets and liabilities. Actual results may differ significantly from these estimates, which may be impacted by future decisions made by the OEB or the Province.

Rate Setting

The Company's Transmission Business includes the separately regulated transmission businesses of Hydro One Networks and B2M Limited Partnership (B2M LP). The Company's consolidated Distribution Business includes the separately regulated distribution businesses of Hydro One Networks and the newly acquired Norfolk Power, as well as the subsidiaries Hydro One Brampton Networks and Hydro One Remote Communities.

The OEB has approved the use of US GAAP for rate setting and regulatory accounting and reporting by Hydro One Networks' transmission and distribution businesses, as well as by Hydro One Remote Communities, beginning with the year 2012. Up to the year ended December 31, 2014, Hydro One Brampton Networks used Canadian GAAP (Part V) for its distribution rate-setting purposes, and has transitioned to International Financial Reporting Standards beginning on January 1, 2015.

Transmission

In May 2012, Hydro One Networks filed a cost-of-service application with the OEB for 2013 and 2014 transmission rates. In December 2012, the OEB approved the 2013 and 2014 revenue requirement of $1,438 million and $1,528 million, respectively.

In December 2013, Hydro One Networks filed a draft Rate Order with the OEB for 2014 transmission rates. The 2014 transmission revenue requirement was increased to $1,535 million from the originally-approved revenue requirement of $1,528 million, primarily due to changes in the cost of capital parameters for 2014 released by the OEB in November 2013. On January 9, 2014, the OEB approved the draft Rate Order for 2014 transmission rates as filed.

Distribution

In June 2012, Hydro One Networks filed an Incentive Regulation Mechanism (IRM) application with the OEB for 2013 distribution rates, to be effective January 1, 2013. In December 2012, the OEB issued its final Decision, which resulted in an increase in distribution rates of approximately 1.3% in 2013, or 0.4% when considering total bill impact, for a typical residential customer consuming 800 kWh per month. In April 2013, Hydro One Networks filed an IRM application with the OEB for 2014 distribution rates, to be effective January 1, 2014. In December 2013, the OEB issued its final Decision, which resulted in an increase in distribution rates of approximately 2.4% in 2014, or 0.85% when considering total bill impact, for a typical residential customer consuming 800 kWh per month.

In August 2012, Hydro One Brampton Networks filed an IRM application with the OEB for 2013 distribution rates, to be effective January 1, 2013. In December 2012, the OEB issued its final Decision, which resulted in an increase in distribution rates of approximately 0.3% in 2013, or less than 0.1% when considering total bill impact, for a typical residential customer consuming 800 kWh per month. In August 2013, Hydro One Brampton Networks filed an IRM application with the OEB for 2014 distribution rates, to be effective January 1, 2014. In December 2013, the OEB issued its final Decision, which resulted in a reduction in distribution rates of approximately 2.3% in 2014, or 0.5% when considering total bill impact, for a typical residential customer consuming 800 kWh per month.

In September 2012, Hydro One Remote Communities filed a cost-of-service application with the OEB for 2013 rates, seeking approval for a 2013 revenue requirement of $53 million. In June 2013, the OEB approved a revenue requirement of $51 million for 2013. In October 2013, Hydro One Remote Communities filed an IRM application with the OEB for 2014 rates, seeking approval for a rate increase of approximately 0.5%. In March 2014, the OEB approved an increase of approximately 1.7% to basic rates for the distribution and generation of electricity, with an effective date of May 1, 2014. The final rate increase was adjusted by the OEB's updated rate adjustment parameters and Hydro One Remote Communities' IRM stretch factor.

Regulatory Accounting

The OEB has the general power to include or exclude revenues, costs, gains or losses in the rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have been applied in an unregulated company. Such change in timing involves the application of rate-regulated accounting, giving rise to the recognition of regulatory assets and liabilities. The Company's regulatory assets represent certain amounts receivable from future customers and costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. In addition, the Company has recorded regulatory liabilities that generally represent amounts that are refundable to future customers. The Company continually assesses the likelihood of recovery of each of its regulatory assets and continues to believe that it is probable that the OEB will factor its regulatory assets and liabilities into the setting of future rates. If, at some future date, the Company judges that it is no longer probable that the OEB will include a regulatory asset or liability in setting future rates, the appropriate carrying amount will be reflected in results of operations in the period that the assessment is made.

Cash and Cash Equivalents

Cash and cash equivalents include cash and short-term investments with an original maturity of three months or less.

Revenue Recognition

Transmission revenues are collected through OEB-approved rates, which are based on an approved revenue requirement that includes a rate of return. Such revenue is recognized as electricity is transmitted and delivered to customers.

Distribution revenues are recognized on an accrual basis and include billed and unbilled revenues. Distribution revenues attributable to the delivery of electricity are based on OEB-approved distribution rates and are recognized as electricity is delivered to customers. The Company estimates monthly revenue for a period based on wholesale electricity purchases because customer meters are not generally read at the end of each month. At the end of each month, the electricity delivered to customers, but not billed, is estimated and revenue is recognized. The unbilled revenue estimate is affected by energy demand, weather, line losses and changes in the composition of customer classes.

Distribution revenue also includes an amount relating to rate protection for rural, residential and remote customers, which is received from the Independent Electricity System Operator (IESO) based on a standardized customer rate that is approved by the OEB. Current legislation provides rate protection for prescribed classes of rural, residential and remote consumers by reducing the electricity rates that would otherwise apply.

Revenues also include amounts related to sales of other services and equipment. Such revenue is recognized as services are rendered or as equipment is delivered.

Revenues are recorded net of indirect taxes.

Accounts Receivable and Allowance for Doubtful Accounts

Billed accounts receivable are recorded at the invoiced amount, net of allowance for doubtful accounts. Unbilled accounts receivable are estimated and recorded based on wholesale electricity purchases. Overdue amounts related to regulated billings bear interest at OEB-approved rates. The allowance for doubtful accounts reflects the Company's best estimate of losses on billed accounts receivable balances. The allowance is based on accounts receivable aging, historical experience and other currently available information. The Company estimates the allowance for doubtful accounts on customer receivables by applying internally developed loss rates to the outstanding receivable balances by risk segment. Risk segments represent groups of customers with similar credit quality indicators and are computed based on various attributes, including number of days receivables are past due, delinquency of balances and payment history. Loss rates applied to the accounts receivable balances are based on historical average write-offs as a percentage of accounts receivable in each risk segment. An account is considered delinquent if the final amount billed is not received within 110 days of the invoiced date. Accounts receivable are written off against the allowance when they are deemed uncollectible. The existing allowance for uncollectible accounts will continue to be affected by changes in volume, prices and economic conditions.

Noncontrolling interest

Noncontrolling interest represents the portion of equity ownership in subsidiaries that is not attributable to the Shareholder of the parent company. Noncontrolling interest is initially recorded at fair value and subsequently the amount is adjusted for the proportionate share of net income (loss) and other comprehensive income (loss) attributable to the noncontrolling interest and any dividends or distributions paid to the noncontrolling interest.

If a transaction results in the acquisition of all, or part, of a noncontrolling interest in a subsidiary, the acquisition of the noncontrolling interest is accounted for as an equity transaction. No gain or loss is recognized in consolidated net income or comprehensive income as a result of changes in the noncontrolling interest, unless a change results in the loss of control by the Company.

Corporate Income Taxes

Under the *Electricity Act, 1998*, Hydro One is required to make payments in lieu of corporate income taxes (PILs) to the Ontario Electricity Financial Corporation (OEFC). These payments are calculated in accordance with the rules for computing income and other relevant amounts contained in the *Income Tax Act* (Canada) and the *Taxation Act, 2007* (Ontario) as modified by the *Electricity Act, 1998* and related regulations.

Current and deferred income taxes are computed based on the tax rates and tax laws enacted at the balance sheet date. Tax benefits associated with income tax positions taken, or expected to be taken, in a tax return are recorded only when the "more-likely-than-not" recognition threshold is satisfied and are measured at the largest amount of benefit that has a greater than 50% likelihood of being realized upon settlement. Management evaluates each position based solely on the technical merits and facts and circumstances of the position, assuming the position will be examined by a taxing authority having full knowledge of all relevant information. Significant management judgment is required to determine recognition thresholds and the related amount of tax benefits to be recognized in the Consolidated Financial Statements. Management re-evaluates tax positions each period in which new information about recognition or measurement becomes available.

Current Income Taxes

The provision for current taxes and the assets and liabilities recognized for the current and prior periods are measured at the amounts receivable from, or payable to, the OEFC.

Deferred Income Taxes

Deferred income taxes are provided for using the liability method. Deferred income taxes are recognized based on the estimated future tax consequences attributable to temporary differences between the carrying amount of assets and liabilities in the Consolidated Financial Statements and their corresponding tax bases.

Deferred income tax liabilities are generally recognized on all taxable temporary differences. Deferred tax assets are recognized to the extent that it is more-likely-than-not that these assets will be realized from taxable income available against which deductible temporary differences can be utilized.

Deferred income taxes are calculated at the tax rates that are expected to apply in the period when the liability is settled or the asset is realized, based on the tax rates and tax laws that have been enacted at the balance sheet date. Deferred income taxes that are not included in the rate-setting process are charged or credited to the Consolidated Statements of Operations and Comprehensive Income.

If management determines that it is more-likely-than-not that some or all of a deferred income tax asset will not be realized, a valuation allowance is recorded against the deferred income tax asset to report the net balance at the amount expected to be realized. Previously unrecognized deferred income tax assets are reassessed at each balance sheet date and are recognized to the extent that it has become more-likely-than-not that the tax benefit will be realized.

The Company records regulatory assets and liabilities associated with deferred income taxes that will be included in the rate-setting process.

The Company uses the flow-through method to account for investment tax credits (ITCs) earned on eligible scientific research and experimental development expenditures, and apprenticeship job creation. Under this method, only non-refundable ITCs are recognized as a reduction to income tax expense.

Materials and Supplies

Materials and supplies represent consumables, small spare parts and construction materials held for internal construction and maintenance of property, plant and equipment. These assets are carried at average cost less any impairments recorded.

Property, Plant and Equipment

Property, plant and equipment is recorded at original cost, net of customer contributions received in aid of construction and any accumulated impairment losses. The cost of additions, including betterments and replacement asset components, is included on the Consolidated Balance Sheets as property, plant and equipment.

The original cost of property, plant and equipment includes direct materials, direct labour (including employee benefits), contracted services, attributable capitalized financing costs, asset retirement costs, and direct and indirect overheads that are related to the capital project or program. Indirect overheads include a portion of corporate costs such as finance, treasury, human resources, information technology and executive costs. Overhead costs, including corporate functions and field services costs, are capitalized on a fully allocated basis, consistent with an OEB-approved methodology.

Property, plant and equipment in service consists of transmission, distribution, communication, administration and service assets and land easements. Property, plant and equipment also includes future use assets, such as land, major components and spare parts, and capitalized project development costs associated with deferred capital projects.

Transmission

Transmission assets include assets used for the transmission of high-voltage electricity, such as transmission lines, support structures, foundations, insulators, connecting hardware and grounding systems, and assets used to step up the voltage of electricity from generating stations for transmission and to step down voltages for distribution, including transformers, circuit breakers and switches.

Distribution

Distribution assets include assets related to the distribution of low-voltage electricity, including lines, poles, switches, transformers, protective devices and metering systems.

Communication

Communication assets include the fibre optic and microwave radio system, optical ground wire, towers, telephone equipment and associated buildings.

Administration and Service

Administration and service assets include administrative buildings, personal computers, transport and work equipment, tools and other minor assets.

Easements

Easements include statutory rights of use for transmission corridors and abutting lands granted under the *Reliable Energy and Consumer Protection Act, 2002*, as well as other land access rights.

Intangible Assets

Intangible assets separately acquired or internally developed are measured on initial recognition at cost, which comprises purchased software, direct labour (including employee benefits), consulting, engineering, overheads and attributable capitalized financing charges. Following initial recognition, intangible assets are carried at cost, net of any accumulated amortization and accumulated impairment losses. The Company's intangible assets primarily represent major company-wide computer applications.

Capitalized Financing Costs

Capitalized financing costs represent interest costs attributable to the construction of property, plant and equipment or development of intangible assets. The financing cost of attributable borrowed funds is capitalized as part of the acquisition cost of such assets. The capitalized portion of financing costs is a reduction to financing charges recognized in the Consolidated Statements of Operations and Comprehensive Income. Capitalized financing costs are calculated using the Company's weighted average effective cost of debt.

Construction and Development in Progress

Construction and development in progress consists of the capitalized cost of constructed assets that are not yet complete and which have not yet been placed in service.

Depreciation and Amortization

The cost of property, plant and equipment and intangible assets is depreciated or amortized on a straight-line basis based on the estimated remaining service life of each asset category, except for transport and work equipment, which is depreciated on a declining balance basis.

The Company periodically initiates an external independent review of its property, plant and equipment and intangible asset depreciation and amortization rates, as required by the OEB. Any changes arising from OEB approval of such a review are implemented on a remaining service life basis, consistent with their inclusion in electricity rates. The last review resulted in changes to rates effective January 1, 2013. A summary of average service lives and depreciation and amortization rates for the various classes of assets is included below:

	Average Service Life	Rate	
		Range	Average
Transmission	57 years	1% – 2%	2%
Distribution	42 years	1% – 20%	2%
Communication	19 years	1% – 15%	4%
Administration and service	15 years	3% – 20%	7%

The cost of intangible assets is included primarily within the administration and service classification above. Amortization rates for computer applications software and other intangible assets range from 9% to 20%.

In accordance with group depreciation practices, the original cost of property, plant and equipment, or major components thereof, and intangible assets that are normally retired, is charged to accumulated depreciation, with no gain or loss being reflected in results of operations. Where a disposition of property, plant and equipment occurs through sale, a gain or loss is calculated based on proceeds and such gain or loss is included in depreciation expense. Depreciation expense also includes the costs incurred to remove property, plant and equipment where no ARO has been recorded.

Goodwill

Goodwill represents the cost of acquired local distribution companies that is in excess of the fair value of the net identifiable assets acquired at the acquisition date. Goodwill is not included in rate base.

Goodwill is evaluated for impairment on an annual basis, or more frequently if circumstances require. The Company performs a qualitative assessment to determine whether it is more-likely-than-not that the fair value of the applicable reporting unit is less than its carrying amount. If the Company determines, as a result of its qualitative assessment, that it is not more-likely-than-not that the fair value of the applicable reporting unit is less than its carrying amount, no further testing is required. If the Company determines, as a result of its qualitative assessment, that it is more-likely-than-not that the fair value of the applicable reporting unit is less than its carrying amount, a goodwill impairment assessment is performed using a two-step, fair value-based test. The first step compares the fair value of the applicable reporting unit to its carrying amount, including goodwill. If the carrying amount of the applicable reporting unit exceeds its fair value, a second step is performed. The second step requires an allocation of fair value to the individual assets and liabilities using purchase price allocation in order to determine the implied fair value of goodwill. If the implied fair value of goodwill is less than the carrying amount, an impairment loss is recorded as a reduction to goodwill and as a charge to results of operations.

For the year ended December 31, 2014, based on the qualitative assessment performed as at September 30, 2014, the Company has determined that it is not more-likely-than-not that the fair value of each applicable reporting unit assessed is less than its carrying amount. As a result, no further testing was performed, and the Company has concluded that goodwill was not impaired at December 31, 2014.

Long-Lived Asset Impairment

When circumstances indicate the carrying value of long-lived assets may not be recoverable, the Company evaluates whether the carrying value of such assets, excluding goodwill, has been impaired. For such long-lived assets, impairment exists when the carrying value exceeds the sum of the future estimated undiscounted cash flows expected to result from the use and eventual disposition of the asset. When alternative courses of action to recover the carrying amount of a long-lived asset are under consideration, a probability-weighted approach is used to develop estimates of future undiscounted cash flows. If the carrying value of the long-lived asset is not recoverable based on the estimated future undiscounted cash flows, an impairment loss is recorded, measured as the excess of the carrying value of the asset over its fair value. As a result, the asset's carrying value is adjusted to its estimated fair value.

Within its regulated business, the carrying costs of most of Hydro One's long-lived assets are included in rate base where they earn an OEB-approved rate of return. Asset carrying values and the related return are recovered through approved rates. As a result, such assets are only tested for impairment in the event that the OEB disallows recovery, in whole or in part, or if such a disallowance is judged to be probable.

Hydro One regularly monitors the assets of its unregulated Hydro One Telecom subsidiary for indications of impairment. Management assesses the fair value of such long-lived assets using commonly accepted techniques, and may use more than one. Techniques used to determine fair value include, but are not limited to, the use of recent third party comparable sales for reference and internally developed discounted cash flow analysis. Significant changes in market conditions, changes to the condition of an asset, or a change in management's intent to utilize the asset are generally viewed by management as triggering events to reassess the cash flows related to these long-lived assets. As at December 31, 2014, no asset impairment had been recorded for assets within either the Company's regulated or unregulated businesses.

Costs of Arranging Debt Financing

For financial liabilities classified as other than held-for-trading, the Company defers the external transaction costs related to obtaining debt financing and presents such amounts as deferred debt issuance costs on the Consolidated Balance Sheets. Deferred debt issuance costs are amortized over the contractual life of the related debt on an effective-interest basis and the amortization is included within financing charges in the Consolidated Statements of Operations and Comprehensive Income. Transaction costs for items classified as held-for-trading are expensed immediately.

Comprehensive Income

Comprehensive income is comprised of net income and other comprehensive income (OCI). Hydro One presents net income and OCI in a single continuous Consolidated Statement of Operations and Comprehensive Income.

Financial Assets and Liabilities

All financial assets and liabilities are classified into one of the following five categories: held-to-maturity; loans and receivables; held-for-trading; other liabilities; or available-for-sale. Financial assets and liabilities classified as held-for-trading are measured at fair value. All other financial assets and liabilities are measured at amortized cost, except accounts receivable and amounts due from related parties, which are measured at the lower of cost or fair value. Accounts receivable and amounts due from related parties are classified as loans and receivables. The Company considers the carrying amounts of accounts receivable and amounts due from related parties to be reasonable estimates of fair value because of the short time to maturity of these instruments. Provisions for impaired accounts receivable are recognized as adjustments to the allowance for doubtful accounts and are recognized when there is objective evidence that the Company will not be able to collect amounts according to the original terms. All financial instrument transactions are recorded at trade date.

Derivative instruments are measured at fair value. Gains and losses from fair valuation are included within financing charges in the period in which they arise. The Company determines the classification of its financial assets and liabilities at the date of initial recognition. The Company designates certain of its financial assets and liabilities to be held at fair value, when it is consistent with the Company's risk management policy disclosed in Note 13 – Fair Value of Financial Instruments and Risk Management.

Derivative Instruments and Hedge Accounting

The Company closely monitors the risks associated with changes in interest rates on its operations and, where appropriate, uses various instruments to hedge these risks. Certain of these derivative instruments qualify for hedge accounting and are designated as accounting hedges, while others either do not qualify as hedges or have not been designated as hedges (hereinafter referred to as undesignated contracts) as they are part of economic hedging relationships.

The accounting guidance for derivative instruments requires the recognition of all derivative instruments not identified as meeting the normal purchase and sale exemption as either assets or liabilities recorded at fair value on the Consolidated Balance Sheets. For derivative instruments that qualify for hedge accounting, the Company may elect to designate such derivative instruments as either cash flow hedges or fair value hedges. The Company offsets fair value amounts recognized on its Consolidated Balance Sheets related to derivative instruments executed with the same counterparty under the same master netting agreement.

For derivative instruments that qualify for hedge accounting and which are designated as cash flow hedges, the effective portion of any gain or loss, net of tax, is reported as a component of accumulated OCI (AOCI) and is reclassified to results of operations in the same period or periods during which the hedged transaction affects results of operations. Any gains or losses on the derivative instrument that represent either hedge ineffectiveness or hedge components excluded from the assessment of effectiveness are recognized in results of operations. For fair value hedges, changes in fair value of both the derivative instrument and the underlying hedged exposure are recognized in the Consolidated Statements of Operations and Comprehensive Income in the current period. The gain or loss on the derivative instrument is included in the same line item as the offsetting gain or loss on the hedged item in the Consolidated Statements of Operations and Comprehensive Income. Additionally, the Company enters into derivative agreements that are economic hedges which either do not qualify for hedge accounting or have not been designated as hedges. The changes in fair value of these undesignated derivative instruments are reflected in results of operations.

Embedded derivative instruments are separated from their host contracts and carried at fair value on the Consolidated Balance Sheets when: (a) the economic characteristics and risks of the embedded derivative are not clearly and closely related to the economic characteristics and risks of the host contract; (b) the hybrid instrument is not measured at fair value, with changes in fair value recognized in results of operations each period; and (c) the embedded derivative itself meets the definition of a derivative. The Company does not engage in derivative trading or speculative activities and had no embedded derivatives at December 31, 2014 or 2013.

Hydro One periodically develops hedging strategies taking into account risk management objectives. At the inception of a hedging relationship where the Company has elected to apply hedge accounting, Hydro One formally documents the relationship between the hedged item and the hedging instrument, the related risk management objective, the nature of the specific risk exposure being hedged, and the method for assessing the effectiveness of the hedging relationship. The Company also assesses, both at the inception of the hedge and on a quarterly basis, whether the hedging instruments are effective in offsetting changes in fair values or cash flows of the hedged items.

Employee Future Benefits

Employee future benefits provided by Hydro One include pension, post-retirement and post-employment benefits. The costs of the Company's pension, post-retirement and post-employment benefit plans are recorded over the periods during which employees render service.

The Company recognizes the funded status of its pension, post-retirement and post-employment plans on its Consolidated Balance Sheets and subsequently recognizes the changes in funded status at the end of each reporting year. Pension, post-retirement and post-employment plans are considered to be underfunded when the projected benefit obligation exceeds the fair value of the plan assets. Liabilities are recognized on the Consolidated Balance Sheets for any net underfunded projected benefit obligation. The net underfunded projected benefit obligation may be disclosed as a current liability, long-term liability, or both. The current portion is the amount by which the actuarial present value of benefits included in the benefit obligation payable in the next 12 months exceeds the fair value of plan assets. If the fair value of plan assets exceeds the projected benefit obligation of the plan, an asset is recognized equal to the net overfunded projected benefit obligation. The post-retirement and post-employment benefit plans are unfunded because there are no related plan assets.

Pension benefits

In accordance with the OEB's rate orders, pension costs are recorded on a cash basis as employer contributions are paid to the pension fund in accordance with the *Pension Benefits Act* (Ontario). Pension costs are recorded on an accrual basis for financial reporting purposes. Pension costs are actuarially determined using the projected benefit method prorated on service and are based on assumptions that reflect management's best estimate of the effect of future events, including future compensation increases. Past service costs from plan amendments and all actuarial gains and losses are amortized on a straight-line basis over the expected average remaining service period of active employees in the plan, and over the estimated remaining life expectancy of inactive employees in the plan. Pension plan assets, consisting primarily of listed equity securities as well as corporate and government debt securities, are fair valued at the end of each year.

Hydro One records a regulatory asset equal to the net underfunded projected benefit obligation for its pension plan. The regulatory asset for the net underfunded projected benefit obligation for the pension plan, in the absence of regulatory accounting, would be recognized in AOCI. A regulatory asset is recognized because management considers it to be probable that pension benefit costs will be recovered in the future through the rate-setting process. The pension regulatory assets are remeasured at the end of each year based on the current status of the pension plan.

All future pension benefit costs are attributed to labour and are either charged to results of operations or capitalized as part of the cost of property, plant and equipment and intangible assets.

Post-retirement and post-employment benefits

Post-retirement and post-employment benefits are recorded and included in rates on an accrual basis. Costs are determined by independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect management's best estimates. Past service costs from plan amendments are amortized to results of operations based on the expected average remaining service period.

Hydro One records a regulatory asset equal to the incremental net unfunded projected benefit obligation for post-retirement and post-employment plans recorded at each year end based on annual actuarial reports. The regulatory asset for the incremental net unfunded projected benefit obligation for post-retirement and post-employment plans, in the absence of regulatory accounting, would be recognized in AOCI. A regulatory asset is recognized because management considers it to be probable that post-retirement and post-employment benefit costs will be recovered in the future through the rate-setting process.

For post-retirement benefits, all actuarial gains or losses are deferred using the "corridor" approach. The amount calculated above the "corridor" is amortized to results of operations on a straight-line basis over the expected average remaining service life of active employees in the plan and over the remaining life expectancy of inactive employees in the plan. The post-retirement benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to the associated regulatory asset, to the extent of the remeasurement adjustment.

For post-employment obligations, the associated regulatory liabilities representing actuarial gains on transition to US GAAP are amortized to results of operations based on the "corridor" approach. Post transition, the actuarial gains and losses on post-employment obligations that are incurred during the year are recognized immediately to results of operations. The post-employment benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to the associated regulatory asset, to the extent of the remeasurement adjustment.

All post-retirement and post-employment future benefit costs are attributed to labour and are either charged to results of operations or capitalized as part of the cost of property, plant and equipment and intangible assets.

Multiemployer Pension Plan

Employees of Hydro One Brampton Networks and the newly acquired Norfolk Power participate in the Ontario Municipal Employees Retirement System Fund (OMERS), a multiemployer, contributory, defined benefit public sector pension fund. OMERS provides retirement pension payments based on members' length of service and salary. Both the participating employers and members are required to make plan contributions. The OMERS plan assets are pooled together to provide benefits to all plan participants and the plan assets are not segregated by member entity. OMERS is registered with the Financial Services Commission of Ontario under Registration #0345983. At December 31, 2013, OMERS had approximately 440,000 members, with approximately 335 members being current employees of Hydro One Brampton Networks and Norfolk Power.

The OMERS plan is accounted for as a defined contribution plan by Hydro One because it is not practicable to determine the present value of the Company's obligation, the fair value of plan assets or the related current service cost applicable to Hydro One Brampton Networks and Norfolk Power employees. Hydro One recognizes its contributions to the OMERS plan as pension expense, with a portion being capitalized. The expensed amount is included in operation, maintenance and administration costs in the Consolidated Statements of Operations and Comprehensive Income.

Loss Contingencies

Hydro One is involved in certain legal and environmental matters that arise in the normal course of business. In the preparation of its Consolidated Financial Statements, management makes judgments regarding the future outcome of contingent events and records a loss for a contingency based on its best estimate when it is determined that such loss is probable and the amount of the loss can be reasonably estimated. Where the loss amount is recoverable in future rates, a regulatory asset is also recorded. When a range estimate for the probable loss exists and no amount within the range is a better estimate than any other amount, the Company records a loss at the minimum amount within the range.

Management regularly reviews current information available to determine whether recorded provisions should be adjusted and whether new provisions are required. Estimating probable losses may require analysis of multiple forecasts and scenarios that often depend on judgments about potential actions by third parties, such as federal, provincial and local courts or regulators. Contingent liabilities are often resolved over long periods of time. Amounts recorded in the Consolidated Financial Statements may differ from the actual outcome once the contingency is resolved. Such differences could have a material impact on future results of operations, financial position and cash flows of the Company.

Provisions are based upon current estimates and are subject to greater uncertainty where the projection period is lengthy. A significant upward or downward trend in the number of claims filed, the nature of the alleged injuries, and the average cost of resolving each claim could change the estimated provision, as could any substantial adverse or favourable verdict at trial. A federal or provincial legislative outcome or structured settlement could also change the estimated liability. Legal fees are expensed as incurred.

Environmental Liabilities

Environmental liabilities are recorded in respect of past contamination when it is determined that future environmental remediation expenditures are probable under existing statute or regulation and the amount of the future expenditures can be reasonably estimated. Hydro One records a liability for the estimated future expenditures associated with the contaminated land assessment and remediation (LAR) and for the phase-out and destruction of polychlorinated biphenyl (PCB)-contaminated mineral oil removed from electrical equipment, based on the present value of these estimated future expenditures. The Company determines the present value with a discount rate equal to its credit-adjusted risk-free interest rate on financial instruments with comparable maturities to the pattern of future environmental expenditures. As the Company anticipates that the future expenditures will continue to be recoverable in future rates, an offsetting regulatory asset has been recorded to reflect the future recovery of these environmental expenditures from customers. Hydro One reviews its estimates of future environmental expenditures annually, or more frequently if there are indications that circumstances have changed.

Asset Retirement Obligations

AROs are recorded for legal obligations associated with the future removal and disposal of long-lived assets. Such obligations may result from the acquisition, construction, development and/or normal use of the asset. Conditional AROs are recorded when there is a legal obligation to perform a future asset retirement activity but where the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the Company. In such a case, the obligation to perform the asset retirement activity is unconditional even though uncertainty exists about the timing and/or method of settlement.

When recording an ARO, the present value of the estimated future expenditures required to complete the asset retirement activity is recorded in the period in which the obligation is incurred, if a reasonable estimate can be made. In general, the present value of the estimated future expenditures is added to the carrying amount of the associated asset and the resulting asset retirement cost is depreciated over the estimated useful life of the asset. Where an asset is no longer in service when an ARO is recorded, the asset retirement cost is recorded in results of operations.

Some of the Company's transmission and distribution assets, particularly those located on unowned easements and rights-of-way, may have AROs, conditional or otherwise. The majority of the Company's easements and rights-of-way are either of perpetual duration or are automatically renewed annually. Land rights with finite terms are generally subject to extension or renewal. As the Company expects to use the majority of its facilities in perpetuity, no ARO currently exists for these assets. If, at some future date, a particular facility is shown not to meet the perpetuity assumption, it will be reviewed to determine whether an estimable ARO exists. In such a case, an ARO would be recorded at that time.

The Company's AROs recorded to date relate to estimated future expenditures associated with the removal and disposal of asbestos-containing materials installed in some of its facilities and with the decommissioning of specific switching stations located on unowned sites.

3. NEW ACCOUNTING PRONOUNCEMENTS

Recently Adopted Accounting Pronouncements

In July 2013, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) 2013-11, Income Taxes (Topic 740): Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists. This ASU provides guidance on the presentation of unrecognized tax benefits. This ASU is effective for fiscal years, and interim periods within those years, beginning after December 15, 2013, and should be applied prospectively to all unrecognized tax benefits that exist at the effective date. The adoption of this ASU did not have a significant impact on the Company's consolidated financial statements.

Recent Accounting Guidance Not Yet Adopted

In May 2014, the FASB issued ASU 2014-09, Revenue from Contracts with Customers (Topic 606). This ASU provides guidance on revenue recognition that depicts the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods and services. This ASU is required to be applied retrospectively and is effective for fiscal years, and interim periods within those years, beginning after December 15, 2016. The Company is currently assessing the impact of adoption of ASU 2014-09 on its consolidated financial statements.

In August 2014, the FASB issued ASU 2014-15, Presentation of Financial Statements – Going Concern (Subtopic 205-40): Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern. This ASU provides guidance about management's responsibility to evaluate whether there is substantial doubt about an entity's ability to continue as a going concern and related disclosures. This ASU is effective for the annual period ending December 31, 2016, and for annual and interim periods thereafter. The adoption of this ASU is not anticipated to have a significant impact on the Company's consolidated financial statements.

In November 2014, the FASB issued ASU 2014-16, Derivatives and Hedging (Topic 815). This ASU provides guidance on accounting for hybrid financial instruments issued in the form of a share. This ASU is effective for fiscal years, and interim periods within those years, beginning after December 15, 2015. The Company is currently assessing the impact of adoption of ASU 2014-16 on its consolidated financial statements.

4. BUSINESS COMBINATIONS

B2M Limited Partnership

In 2012, Hydro One entered into an agreement with the Chippewas of Nawash First Nation and the Chippewas of Saugeen First Nation, collectively referred to as the Saugeen Ojibway Nation (SON), where a noncontrolling equity interest in Hydro One's new limited partnership, B2M LP, would be made available for purchase at fair value by the SON. B2M LP was formed by Hydro One in 2013 to hold most of the transmission lines and a licence to use the related land. These assets are associated with Hydro One's Bruce to Milton Transmission Reinforcement Project, an electricity transmission line (Bruce to Milton Line) in southwestern Ontario, from the Bruce Power facility in Kincardine to Hydro One's Milton Switching Station in the Town of Milton. Hydro One Networks will maintain and operate the Bruce to Milton Line in accordance with an operation and management services agreement. In November 2013, the OEB issued a Decision and Order granting B2M LP a transmission licence and granting Hydro One Networks leave to sell the relevant Bruce to Milton Line transmission assets to B2M LP.

On December 16, 2014, the relevant Bruce to Milton Line transmission assets totalling $526 million were transferred from Hydro One Networks to B2M LP. This was financed by 60% debt ($316 million) and 40% equity ($210 million). On December 17, 2014, the SON acquired a 34.2% equity interest in B2M LP for consideration of $72 million, representing the fair value of the equity interest acquired.

Part of the SON's equity interest in B2M LP is in Class B units of B2M LP that have a mandatory put option. The put option requires that upon the occurrence of an enforcement event (i.e. an event of default such as a debt default by the SON or insolvency event), the SON has the ability to require Hydro One to purchase the Class B units of B2M LP for net book value on the redemption date.

The noncontrolling interest relating to the Class B units is classified on the Consolidated Balance Sheet as temporary equity because the redemption feature is outside the control of the Company. The balance of the noncontrolling interest is classified within equity. At December 31, 2014, the total noncontrolling interest was reduced by the 2014 net loss attributable to noncontrolling interest totalling $2 million, including $1 million relating to noncontrolling interest subject to redemption.

Acquisition of Norfolk Power

On August 29, 2014, Hydro One acquired 100% of the common shares of Norfolk Power, an electricity distribution and telecom company located in southwestern Ontario. The total purchase price for Norfolk Power, net of the long-term debt assumed and adjusted for preliminary working capital and other closing adjustments, is approximately $68 million.

The following table summarizes the preliminary determination of the fair value of the assets acquired and liabilities assumed:

(millions of Canadian dollars)	
Working capital	6
Property, plant and equipment	56
Deferred income tax assets	1
Goodwill	40
Bank indebtedness	(3)
Derivative instruments	(3)
Long-term debt	(26)
Post-retirement and post-employment benefit liability	(1)
Environmental liability	(1)
Long-term accounts payable and other liabilities	(1)
	68

The determination of the fair values of assets acquired and liabilities assumed has been based upon management's estimates and certain assumptions with respect to the fair values of the assets acquired and liabilities assumed. The purchase agreement provides for final purchase price adjustments based on agreed working capital and other balances at the acquisition date which have not yet been finalized. The Company will continue to review information and perform further analysis prior to finalizing the total purchase price and therefore the actual total purchase price and the consequent impact on goodwill may differ from the amounts above.

Goodwill of approximately $40 million arising from the Norfolk Power acquisition consists largely of the synergies and economies of scale expected from combining the operations of Hydro One and Norfolk Power. All of the goodwill was assigned to Hydro One's Distribution Business segment. None of the goodwill recognized is expected to be deductible for income tax purposes.

Norfolk Power contributed revenues of $18 million and net income of less than $1 million to the Company's consolidated financial results for the year ended December 31, 2014.

All costs related to the acquisition have been expensed through the Consolidated Statements of Operations and Comprehensive Income. The disclosure of Norfolk Power's pro forma information is immaterial to the Company's consolidated financial results for the year ended December 31, 2014.

Woodstock Hydro Purchase Agreement

On May 21, 2014, Hydro One reached an agreement with the City of Woodstock to acquire 100% of the common shares of Woodstock Hydro Holdings Inc. (Woodstock Hydro), an electricity distribution company located in southwestern Ontario. The acquisition is pending a regulatory decision from the OEB. The purchase price for Woodstock Hydro will be approximately $29 million, subject to final closing adjustments. The transaction is anticipated to be completed in 2015. In anticipation of the Woodstock Hydro acquisition, the Company made a refundable deposit totalling $2 million, which is recorded in prepaid expenses and other assets on the Consolidated Balance Sheet.

Haldimand Hydro Purchase Agreement

On June 10, 2014, Hydro One reached an agreement with Haldimand County to acquire 100% of the common shares of Haldimand County Utilities Inc. (Haldimand Hydro), an electricity distribution and telecom company located in southwestern Ontario. The acquisition is pending a regulatory decision from the OEB. The purchase price for Haldimand Hydro will be approximately $65 million, subject to final closing adjustments. The transaction is anticipated to be completed in 2015. In anticipation of the Haldimand Hydro acquisition, the Company made a refundable deposit totalling $3 million, which is recorded in prepaid expenses and other assets on the Consolidated Balance Sheet.

5. DEPRECIATION AND AMORTIZATION

Year ended December 31 (millions of Canadian dollars)	**2014**	2013
Depreciation of property, plant and equipment	**565**	533
Amortization of intangible assets	**53**	48
Asset removal costs	**81**	79
Amortization of regulatory assets	**23**	16
	722	676

6. FINANCING CHARGES

Year ended December 31 (millions of Canadian dollars)	**2014**	2013
Interest on long-term debt	**432**	416
Other	**12**	9
Less: Interest capitalized on construction and development in progress	**(49)**	(51)
Gain on interest-rate swap agreements	**(10)**	(11)
Interest earned on investments	**(6)**	(3)
	379	360

7. PROVISION FOR PAYMENTS IN LIEU OF CORPORATE INCOME TAXES

The provision for PILs differs from the amount that would have been recorded using the combined Canadian federal and Ontario statutory income tax rate. The reconciliation between the statutory and the effective tax rates is provided as follows:

Year ended December 31 (millions of Canadian dollars)	**2014**	2013
Income before provision for PILs	**836**	912
Canadian federal and Ontario statutory income tax rate	**26.50%**	26.50%
Provision for PILs at statutory rate	**222**	242
Increase (decrease) resulting from:		
Net temporary differences included in amounts charged to customers:		
Capital cost allowance in excess of depreciation and amortization	**(72)**	(72)
Pension contributions in excess of pension expense	**(24)**	(23)
Overheads capitalized for accounting but deducted for tax purposes	**(15)**	(14)
Interest capitalized for accounting but deducted for tax purposes	**(13)**	(13)
Environmental expenditures	**(5)**	(4)
Prior year's adjustments	**(4)**	(8)
Non-refundable investment tax credits	**(3)**	(4)
Post-retirement and post-employment benefit expense in excess of cash payments	**3**	4
Other	**(1)**	(1)
Net temporary differences	**(134)**	(135)
Net permanent differences	**1**	2
Total provision for PILs	**89**	109

The major components of income tax expense are as follows:

Year ended December 31 (millions of Canadian dollars)	**2014**	2013
Current provision for PILs	**79**	111
Deferred provision (recovery) for PILs	**10**	(2)
Total provision for PILs	**89**	109
Effective income tax rate	**10.63%**	11.98%

The current provision for PILs is remitted to, or received from, the OEFC. At December 31, 2014, $39 million due from the OEFC was included in due from related parties on the Consolidated Balance Sheet (2013 – $29 million).

At December 31, 2014, the total provision for PILs includes deferred provision for PILs of $10 million (2013 – deferred recovery of $2 million) that is not included in the rate-setting process, using the liability method of accounting. Deferred PILs balances expected to be included in the rate-setting process are offset by regulatory assets and liabilities to reflect the anticipated recovery or disposition of these balances within future electricity rates.

Deferred Income Tax Assets and Liabilities

Deferred income tax assets and liabilities arise from differences between the carrying amounts and tax basis of the Company's assets and liabilities. At December 31, 2014 and 2013, deferred income tax assets and liabilities consisted of the following:

December 31 (millions of Canadian dollars)	**2014**	2013
Deferred income tax assets		
Post-retirement and post-employment benefits expense in excess of cash payments	**8**	7
Environmental expenditures	**4**	5
Depreciation and amortization in excess of capital cost allowance	**(4)**	–
Other	**(1)**	(1)
Total deferred income tax assets	**7**	11
Less: current portion	**–**	–
	7	11

December 31 (millions of Canadian dollars)	**2014**	2013
Deferred income tax liabilities		
Capital cost allowance in excess of depreciation and amortization	**(1,713)**	(1,556)
Regulatory amounts that are not recognized for tax purposes	**(140)**	(144)
Partnership interest	**(38)**	–
Goodwill	**(21)**	(20)
Post-retirement and post-employment benefits expense in excess of cash payments	**559**	542
Environmental expenditures	**59**	66
Other	**–**	1
Total deferred income tax liabilities	**(1,294)**	(1,111)
Less: current portion	**19**	18
	(1,313)	(1,129)

During 2014 and 2013, there were no changes in the rate applicable to future taxes.

8. ACCOUNTS RECEIVABLE

December 31 (millions of Canadian dollars)	**2014**	2013
Accounts receivable – billed	**496**	268
Accounts receivable – unbilled	**586**	691
Accounts receivable, gross	**1,082**	959
Allowance for doubtful accounts	**(66)**	(36)
Accounts receivable, net	**1,016**	923

The following table shows the movements in the allowance for doubtful accounts for the years ended December 31, 2014 and 2013:

Year ended December 31 (millions of Canadian dollars)	**2014**	2013
Allowance for doubtful accounts – January 1	**(36)**	(23)
Write-offs	**24**	24
Additions to allowance for doubtful accounts	**(54)**	(37)
Allowance for doubtful accounts – December 31	**(66)**	(36)

9. PROPERTY, PLANT AND EQUIPMENT

December 31, 2014 (millions of Canadian dollars)	**Property, Plant and Equipment**	**Accumulated Depreciation**	**Construction in Progress**	**Total**
Transmission	**13,209**	**4,416**	**626**	**9,419**
Distribution	**9,076**	**3,225**	**320**	**6,171**
Communication	**1,100**	**615**	**56**	**541**
Administration and Service	**1,502**	**793**	**23**	**732**
Easements	**623**	**85**	**–**	**538**
	25,510	**9,134**	**1,025**	**17,401**

December 31, 2013 (millions of Canadian dollars)	Property, Plant and Equipment	Accumulated Depreciation	Construction in Progress	Total
Transmission	12,413	4,215	671	8,869
Distribution	8,498	3,046	316	5,768
Communication	1,060	560	53	553
Administration and Service	1,380	716	38	702
Easements	617	78	–	539
	23,968	8,615	1,078	16,431

Financing charges capitalized on property, plant and equipment under construction were $48 million in 2014 (2013 – $48 million).

10. INTANGIBLE ASSETS

December 31, 2014 *(millions of Canadian dollars)*	**Intangible Assets**	**Accumulated Amortization**	**Development in Progress**	**Total**
Computer applications software	**573**	**303**	**3**	**273**
Other	**5**	**2**	**–**	**3**
	578	**305**	**3**	**276**

December 31, 2013 *(millions of Canadian dollars)*	Intangible Assets	Accumulated Amortization	Development in Progress	Total
Computer applications software	557	249	3	311
Other	5	3	–	2
	562	252	3	313

Financing charges capitalized on intangible assets under development were $1 million in 2014 (2013 – $3 million). The estimated annual amortization expense for intangible assets is as follows: 2015 – $53 million; 2016 – $53 million; 2017 – $53 million; 2018 – $45 million; and 2019 – $31 million.

11. REGULATORY ASSETS AND LIABILITIES

Regulatory assets and liabilities arise as a result of the rate-setting process. Hydro One has recorded the following regulatory assets and liabilities:

December 31 (millions of Canadian dollars)	**2014**	2013
Regulatory assets:		
Deferred income tax regulatory asset	**1,327**	1,145
Pension benefit regulatory asset	**1,236**	845
Post-retirement and post-employment benefits	**273**	308
Environmental	**239**	266
Pension cost variance	**90**	80
DSC exemption	**16**	7
OEB cost assessment differential	**12**	9
Retail settlement variance accounts	**11**	–
Long-term project development costs	**–**	5
Other	**27**	18
Total regulatory assets	**3,231**	2,683
Less: current portion	**31**	47
	3,200	2,636
Regulatory liabilities:		
Rider 11	**83**	55
External revenue variance	**54**	81
CDM deferral variance account	**25**	–
Deferred income tax regulatory liability	**21**	19
PST savings deferral	**19**	17
Hydro One Brampton Networks rider	**2**	8
Retail settlement variance accounts	**–**	35
Rider 9	**–**	19
Other	**11**	14
Total regulatory liabilities	**215**	248
Less: current portion	**47**	85
	168	163

Deferred Income Tax Regulatory Asset and Liability

Deferred income taxes are recognized on temporary differences between the carrying amount of assets and liabilities in the financial statements and the corresponding tax bases used in the computation of taxable profit. The Company has recognized regulatory assets and liabilities that correspond to deferred income taxes that flow through the rate-setting process. In the absence of rate-regulated accounting, the Company's provision for PILs would have been recognized using the liability method and there would be no regulatory accounts established for taxes to be recovered through future rates. As a result, the 2014 provision for PILs would have been higher by approximately $132 million (2013 – $139 million).

Pension Benefit Regulatory Asset

The Company recognizes the net unfunded status of pension obligations on the Consolidated Balance Sheets with an offset to the associated regulatory asset. A regulatory asset is recognized because management considers it to be probable that pension benefit costs will be recovered in the future through the rate-setting process. The pension benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to the associated regulatory asset, to the extent of the remeasurement adjustment. In the absence of rate-regulated accounting, 2014 OCI would have been lower by $391 million (2013 – higher by $670 million).

Post-Retirement and Post-Employment Benefits

The Company recognizes the net unfunded status of post-retirement and post-employment obligations on the Consolidated Balance Sheets with an incremental offset to the associated regulatory assets. A regulatory asset is recognized because management considers it to be probable that post-retirement and post-employment benefit costs will be recovered in the future through the rate-setting process. The post-retirement and post-employment benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to the associated regulatory asset, to the extent of the remeasurement adjustment. In the absence of rate-regulated accounting, 2014 OCI would have been higher by $35 million (2013 – $12 million).

Environmental

Hydro One records a liability for the estimated future expenditures required to remediate environmental contamination. Because such expenditures are expected to be recoverable in future rates, the Company has recorded an equivalent amount as a regulatory asset. In 2014, the environmental regulatory asset decreased by $33 million (2013 – $3 million) to reflect related changes in the Company's PCB liability, and increased by $13 million (2013 – $26 million) due to changes in the LAR liability. The environmental regulatory asset is amortized to results of operations based on the pattern of actual expenditures incurred and charged to environmental liabilities. The OEB has the discretion to examine and assess the prudency and the timing of recovery of all of Hydro One's actual environmental expenditures. In the absence of rate-regulated accounting, 2014 operation, maintenance and administration expenses would have been lower by $20 million (2013 – higher by $23 million). In addition, 2014 amortization expense would have been lower by $18 million (2013 – $16 million), and 2014 financing charges would have been higher by $11 million (2013 – $10 million).

Pension Cost Variance

A pension cost variance account was established for Hydro One Networks' transmission and distribution businesses to track the difference between the actual pension expenses incurred and estimated pension costs approved by the OEB. The balance in this regulatory account reflects the excess of pension costs paid as compared to OEB-approved amounts. In the absence of rate-regulated accounting, 2014 revenue would have been lower by $10 million (2013 – $19 million).

DSC Exemption

In June 2010, Hydro One Networks filed an application with the OEB regarding the OEB's new cost responsibility rules contained in the OEB's October 2009 Notice of Amendment to the Distribution System Code (DSC), with respect to the connection of certain renewable generators that were already connected or that had received a connection impact assessment prior to October 21, 2009. The application sought approval to record and defer the unanticipated costs incurred by Hydro One Networks that resulted from the connection of certain renewable generation facilities. The OEB ruled that identified specific expenditures can be recorded in a deferral account subject to the OEB's review until the next Hydro One Networks' distribution cost-of-service application. This program effectively ended at the end of 2014 with no new principal to be recorded in 2015.

OEB Cost Assessment Differential

In April 2010, the OEB issued its Decision regarding Hydro One Networks' distribution rate application for 2010 and 2011. As part of this decision, the OEB also approved the distribution-related OEB Cost Assessment Differential Account to record the difference between the amounts approved in rates and actual expenditures with respect to the OEB's cost assessments. This continued for 2012–2014 until the next Hydro One Networks' distribution cost-of-service application, which was submitted in 2014. This program effectively ended at the end of 2014 with no new activity to be recorded in 2015.

Retail Settlement Variance Accounts (RSVAs)

Hydro One has deferred certain retail settlement variance amounts under the provisions of Article 490 of the OEB's Accounting Procedures Handbook. In December 2012, the OEB approved the disposition of the total RSVA balance accumulated from January 2010 to December 2011, including accrued interest, to be disposed over a 24-month period from January 1, 2013 to December 31, 2014. At December 31, 2014, the RSVA was in a net asset position due to a change in global adjustment.

Long-Term Project Development Costs

In May 2009, the OEB approved the creation of a deferral account to record Hydro One Networks' costs of preliminary work to advance certain transmission projects identified in the Company's 2009 and 2010 transmission rate applications. In March 2010, the OEB issued a decision amending the scope of the account to include the 20 major transmission projects identified in the September 2009 request from the Ministry of Energy and Infrastructure. In December 2012, the OEB approved the recovery of the December 31, 2012 balance, including accrued interest, to be recovered over a one-year period from January 1, 2014 to December 31, 2014.

Rider 11

In April 2010, the OEB requested the establishment of deferral accounts which capture the difference between the revenue recorded on the basis of Green Energy Plan expenditures incurred and the actual recoveries received. Rider 11 includes amounts previously included as Rider 8.

External Revenue Variance

In May 2009, the OEB approved forecasted amounts related to export service revenue, external revenue from secondary land use, and external revenue from station maintenance and engineering and construction work. In November 2012, the OEB again approved forecasted amounts related to these revenue categories and extended the scope to encompass all other external revenues. The external revenue variance account balance reflects the excess of actual external revenues compared to the OEB-approved forecasted amounts.

CDM Deferral Variance Account

As part of Hydro One Networks' application for 2013 and 2014 transmission rates, Hydro One agreed to establish a new regulatory deferral variance account to track the impact of actual Conservation and Demand Management (CDM) and demand response results on the load forecast compared to the estimated load forecast included in the revenue requirement. The balance in the CDM deferral variance account relates to the actual 2013 CDM compared to the amounts included in 2013 revenue requirement. The OEB rate order specifically states that the Ontario Power Authority (OPA) data used to calculate the difference between forecasted and actual savings will be provided one year in arrears, and as a result, no amount should be recorded in advance of notification from the OPA of actual results. This notification from the OPA typically occurs in September of each year.

PST Savings Deferral Account

The provincial sales tax (PST) and goods and services tax (GST) were harmonized in July 2010. Unlike the GST, the PST was included in operation, maintenance and administration expenses or capital expenditures for past revenue requirements approved during a full cost-of-service hearing. Under the harmonized sales tax (HST) regime, the HST included in operation, maintenance and administration expenses or capital expenditures is not a cost ultimately borne by the Company and as such, a refund of the prior PST element in the approved revenue requirement is applicable, and calculations for tracking and refund were requested by the OEB. For Hydro One Networks' transmission revenue requirement, PST was included between July 1, 2010 and December 31, 2010 and recorded in a deferral account, per direction from the OEB. For Hydro One Networks' distribution revenue requirement, PST was included between July 1, 2010 and December 31, 2014 and recorded in a deferral account, per direction from the OEB.

Hydro One Brampton Networks Rider

In December 2013, the OEB issued a decision for Hydro One Brampton Networks' 2014 distribution rates. Included in the OEB's decision was the approval of certain deferral account balances, primarily RSVAs. The OEB ordered that the approved balances be aggregated into a single regulatory account and disposed of through a rate rider over a two-year period from January 1, 2014 to December 31, 2015.

Rider 9

In December 2012, as part of Hydro One Networks' 2013 IRM distribution rate application, the OEB approved for disposition certain distribution-related deferral account balances, including RSVA amounts and balances of Rider 2 and Rider 3, accumulated up to December 2011, including accrued interest, to be disposed over a 24-month period from January 1, 2013 to December 31, 2014.

12. DEBT AND CREDIT AGREEMENTS

Short-Term Notes

Hydro One meets its short-term liquidity requirements in part through the issuance of commercial paper under its Commercial Paper Program which has a maximum authorized amount of $1,000 million. These short-term notes are denominated in Canadian dollars with varying maturities not exceeding 365 days. Hydro One had no commercial paper borrowings outstanding as at December 31, 2014 and 2013.

Hydro One has a $1,500 million committed and unused revolving standby credit facility with a syndicate of banks, maturing in June 2019. If used, interest on the facility would apply based on Canadian benchmark rates. This credit facility is unsecured and supports the Company's Commercial Paper Program. The Company may use the credit facility for general corporate purposes, including meeting short-term funding requirements. The obligation of each lender to make any credit extension to the Company under its credit facility is subject to various conditions including, among other things, that no event of default has occurred or would result from such credit extension.

Long-Term Debt

The Company issues notes for long-term financing under its Medium-Term Note (MTN) Program. The maximum authorized principal amount of notes issuable under this program is $3,000 million. At December 31, 2014, $1,187 million remained available for issuance until October 2015.

The following table presents the outstanding long-term debt at December 31, 2014 and 2013:

December 31 (millions of Canadian dollars)	**2014**	2013
3.13% Series 19 notes due 2014[1]	–	750
2.95% Series 21 notes due 2015[1]	**500**	500
Floating-rate Series 22 notes due 2015[2]	**50**	50
4.64% Series 10 notes due 2016	**450**	450
Floating-rate Series 27 notes due 2016[2]	**50**	50
5.18% Series 13 notes due 2017	**600**	600
2.78% Series 28 notes due 2018	**750**	750
Floating-rate Series 31 notes due 2019[2]	**228**	–
4.40% Series 20 notes due 2020	**300**	300
3.20% Series 25 notes due 2022	**600**	600
7.35% Debentures due 2030	**400**	400
6.93% Series 2 notes due 2032	**500**	500
6.35% Series 4 notes due 2034	**385**	385
5.36% Series 9 notes due 2036	**600**	600
4.89% Series 12 notes due 2037	**400**	400
6.03% Series 17 notes due 2039	**300**	300
5.49% Series 18 notes due 2040	**500**	500
4.39% Series 23 notes due 2041	**300**	300
6.59% Series 5 notes due 2043	**315**	315
4.59% Series 29 notes due 2043	**435**	435
4.17% Series 32 notes due 2044	**350**	–
5.00% Series 11 notes due 2046	**325**	325
4.00% Series 24 notes due 2051	**225**	225
3.79% Series 26 notes due 2062	**310**	310
4.29% Series 30 notes due 2064	**50**	–
	8,923	9,045
Add: Unrealized mark-to-market loss[1]	**2**	12
Less: Long-term debt payable within one year	**(552)**	(756)
Long-term debt	**8,373**	8,301

[1] The unrealized mark-to-market loss relates to $250 million of the Series 21 notes due 2015 (2013 – $500 million of the Series 19 notes due 2014, and $250 million of the Series 21 notes due 2015). The unrealized mark-to-market loss is offset by a $2 million (2013 – $12 million) unrealized mark-to-market gain on the related fixed-to-floating interest-rate swap agreements, which are accounted for as fair value hedges. See Note 13 – Fair Value of Financial Instruments and Risk Management for details of fair value hedges.

[2] The interest rates of the floating-rate notes are referenced to the 3-month Canadian dollar bankers' acceptance rate, plus a margin

In 2014, Hydro One issued $628 million (2013 – $1,185 million) of long-term debt under the MTN Program, and repaid the $750 million MTN Series 19 notes (2013 – repaid $600 million MTN Series 15 notes). In addition, the Company repaid long-term debt totalling $26 million assumed on the Norfolk Power acquisition.

The long-term debt is unsecured and denominated in Canadian dollars. The long-term debt is summarized by the number of years to maturity in Note 13 – Fair Value of Financial Instruments and Risk Management.

13. FAIR VALUE OF FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Fair value is considered to be the exchange price in an orderly transaction between market participants to sell an asset or transfer a liability at the measurement date. The fair value definition focuses on an exit price, which is the price that would be received in the sale of an asset or the amount that would be paid to transfer a liability.

Hydro One classifies its fair value measurements based on the following hierarchy, as prescribed by the accounting guidance for fair value, which prioritizes the inputs to valuation techniques used to measure fair value into three levels:

Level 1 inputs are unadjusted quoted prices in active markets for identical assets or liabilities that Hydro One has the ability to access. An active market for the asset or liability is one in which transactions for the asset or liability occur with sufficient frequency and volume to provide ongoing pricing information.

Level 2 inputs are those other than quoted market prices that are observable, either directly or indirectly, for an asset or liability. Level 2 inputs include, but are not limited to, quoted prices for similar assets or liabilities in an active market, quoted prices for identical or similar assets or liabilities in markets that are not active and inputs other than quoted market prices that are observable for the asset or liability, such as interest-rate curves and yield curves observable at commonly quoted intervals, volatilities, credit risk and default rates. A Level 2 measurement cannot have more than an insignificant portion of the valuation based on unobservable inputs.

Level 3 inputs are any fair value measurements that include unobservable inputs for the asset or liability for more than an insignificant portion of the valuation. A Level 3 measurement may be based primarily on Level 2 inputs.

Non-Derivative Financial Assets and Liabilities

At December 31, 2014 and 2013, the Company's carrying amounts of accounts receivable, due from related parties, cash and cash equivalents, bank indebtedness, accounts payable, and due to related parties are representative of fair value because of the short-term nature of these instruments.

Fair Value Measurements of Long-Term Debt

The fair values and carrying values of the Company's long-term debt at December 31, 2014 and 2013 are as follows:

December 31 *(millions of Canadian dollars)*	**2014 Carrying Value**	**2014 Fair Value**	2013 Carrying Value	2013 Fair Value
Long-term debt				
$500 million of MTN Series 19 notes[1]	–	–	506	506
$250 million of MTN Series 21 notes[1]	**252**	**252**	256	256
Other notes and debentures[2]	**8,673**	**10,159**	8,295	9,018
	8,925	**10,411**	9,057	9,780

[1] The fair value of $500 million of the MTN Series 19 notes and of $250 million of the MTN Series 21 notes subject to hedging is primarily based on changes in the present value of future cash flows due to a change in the yield in the swap market for the related swap (hedged risk).

[2] The fair value of other notes and debentures, and the portions of the MTN Series 19 notes and the MTN Series 21 notes that are not subject to hedging, represents the market value of the notes and debentures and is based on unadjusted period-end market prices for the same or similar debt of the same remaining maturities.

Fair Value Measurements of Derivative Instruments

At December 31, 2014, the Company had interest-rate swaps totalling $250 million (2013 – $750 million) that were used to convert fixed-rate debt to floating-rate debt. These swaps are classified as fair value hedges. The Company's fair value hedge exposure was equal to about 3% (2013 – 8%) of its total long-term debt of $8,925 million (2013 – $9,057 million). At December 31, 2014, the Company had the following interest-rate swaps designated as fair value hedges:

(a) two $125 million fixed-to-floating interest-rate swap agreements to convert $250 million of the $500 million MTN Series 21 notes maturing September 11, 2015 into three-month variable-rate debt.

At December 31, 2014, the Company also had interest-rate swaps with a total notional value of $409 million (2013 – $900 million) classified as undesignated contracts. The undesignated contracts consist of the following interest-rate swaps:

(b) a $150 million floating-to-fixed interest-rate swap agreement that locks in the floating rate the Company pays on a portion of the above fixed-to-floating interest-rate swaps from December 11, 2014 to September 11, 2015;

(c) a $50 million floating-to-fixed interest-rate swap agreement that locks in the floating rate the Company pays on the $50 million floating-rate MTN Series 22 notes from January 24, 2014 to January 24, 2015;

(d) a $137 million floating-to-fixed interest-rate swap agreement that locks in the floating rate the Company pays on the $228 million floating-rate MTN Series 31 notes from December 22, 2014 to December 21, 2015;

(e) a $30 million floating-to-fixed interest-rate swap agreement that locks in the floating rate the Company pays on the $50 million floating-rate MTN Series 27 notes from March 3, 2015 to December 3, 2015;

(f) a $30 million floating-to-fixed interest-rate swap agreement that locks in the floating rate the Company pays on the $50 million floating-rate MTN Series 22 notes from January 26, 2015 to July 24, 2015; and

(g) three interest-rate swaps with a total notional value of $12 million that were assumed as part of the Norfolk Power acquisition. These swaps consist of $8 million and $2 million floating-to-fixed interest-rate swap agreements maturing on September 20, 2029, and a $2 million floating-to-fixed interest-rate swap agreement maturing on September 20, 2019.

Fair Value Hierarchy

The fair value hierarchy of financial assets and liabilities at December 31, 2014 and 2013 is as follows:

December 31, 2014 (millions of Canadian dollars)	**Carrying Value**	**Fair Value**	**Level 1**	**Level 2**	**Level 3**
Assets:					
Cash and cash equivalents	**100**	**100**	**100**	–	–
Derivative instruments					
Fair value hedges – interest-rate swaps	**2**	**2**	–	**2**	–
	102	**102**	**100**	**2**	–
Liabilities:					
Bank indebtedness	**2**	**2**	**2**	–	–
Derivative instruments					
Undesignated contracts – interest-rate swaps	**3**	**3**	–	**3**	–
Long-term debt	**8,925**	**10,411**	–	**10,411**	–
	8,930	**10,416**	**2**	**10,414**	–

December 31, 2013 (millions of Canadian dollars)	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Assets:					
Cash and cash equivalents	565	565	565	–	–
Investment	251	251	–	251	–
Derivative instruments					
Fair value hedges – interest-rate swaps	12	12	–	12	–
	828	828	565	263	–
Liabilities:					
Bank indebtedness	31	31	31	–	–
Long-term debt	9,057	9,780	–	9,780	–
	9,088	9,811	31	9,780	–

Cash and cash equivalents include cash and short-term investments. At December 31, 2014, short-term investments consisted of bankers' acceptances and money market funds totalling $nil (2013 – $515 million). The carrying values are representative of fair value because of the short-term nature of these instruments.

The investment at December 31, 2013 represented the Province of Ontario Floating-Rate Notes that matured in November 2014. The fair value of the investment was determined using inputs other than quoted prices that are observable for the asset, with unrecognized gains or losses recognized in financing charges. The Company obtained quotes from an independent third party for the fair value of the investment, who uses the market price of similar securities adjusted for changes in observable inputs such as maturity dates and interest rates.

The fair value of the derivative instruments is determined using inputs other than quoted prices that are observable for these assets. The fair value is primarily based on the present value of future cash flows using a swap yield curve to determine the assumptions for interest rates.

The fair value of the hedged portion of the long-term debt is primarily based on the present value of future cash flows using a swap yield curve to determine the assumption for interest rates. The fair value of the unhedged portion of the long-term debt is based on unadjusted period-end market prices for the same or similar debt of the same remaining maturities.

There were no significant transfers between any of the fair value levels during the years ended December 31, 2014 and 2013.

Risk Management

Exposure to market risk, credit risk and liquidity risk arises in the normal course of the Company's business.

Market Risk

Market risk refers primarily to the risk of loss that results from changes in commodity prices, foreign exchange rates and interest rates. The Company does not have commodity risk. The Company does have foreign exchange risk as it enters into agreements to purchase materials and equipment associated with capital programs and projects that are settled in foreign currencies. This foreign exchange risk is not material, although the Company could in the future decide to issue foreign currency-denominated debt which would be hedged back to Canadian dollars consistent with its risk management policy. Hydro One is exposed to fluctuations in interest rates as the regulated rate of return for the Company's Transmission and Distribution Businesses is derived using a formulaic approach that is based on the forecast for long-term Government of Canada bond yields and the spread in 30-year "A"-rated Canadian utility bonds over the 30-year benchmark Government of Canada bond yield. The Company estimates that a 1% decrease in the forecasted long-term Government of Canada bond yield or the "A"-rated Canadian utility spread used in determining the Company's rate of return would reduce the Transmission Business' 2014 annual results of operations by approximately $20 million (2013 – $19 million) and Hydro One Networks' distribution business' 2014 annual results of operations by approximately $10 million (2013 – $10 million).

The Company uses a combination of fixed and variable-rate debt to manage the mix of its debt portfolio. The Company also uses derivative financial instruments to manage interest-rate risk. The Company utilizes interest-rate swaps, which are typically designated as fair value hedges, as a means to manage its interest rate exposure to achieve a lower cost of debt. In addition, the Company may utilize interest-rate derivative instruments to lock in interest-rate levels in anticipation of future financing. Hydro One may also enter into derivative agreements such as forward-starting pay fixed-interest-rate swap agreements to hedge against the effect of future interest-rate movements on long-term fixed-rate borrowing requirements. Such arrangements are typically designated as cash flow hedges. No cash flow hedge agreements were in existence as at December 31, 2014 or 2013.

A hypothetical 10% increase in the interest rates associated with variable-rate debt would not have resulted in a significant decrease in Hydro One's results of operations for the years ended December 31, 2014 or 2013.

Fair Value Hedges

For derivative instruments that are designated and qualify as fair value hedges, the gain or loss on the derivative as well as the offsetting loss or gain on the hedged item attributable to the hedged risk are recognized in the Consolidated Statements of Operations and Comprehensive Income. The net unrealized loss (gain) on the hedged debt and the related interest-rate swaps for the years ended December 31, 2014 and 2013 are included in financing charges as follows:

Year ended December 31 (millions of Canadian dollars)	**2014**	2013
Unrealized loss (gain) on hedged debt	**(3)**	(8)
Unrealized loss (gain) on fair value interest-rate swaps	**3**	8
Net unrealized loss (gain)	**–**	–

At December 31, 2014, Hydro One had $250 million (2013 – $750 million) of notional amounts of fair value hedges outstanding related to interest-rate swaps, with assets at fair value of $2 million (2013 – $12 million). During the years ended December 31, 2014 and 2013, there was no significant impact on the results of operations as a result of any ineffectiveness attributable to fair value hedges.

Credit Risk

Financial assets create a risk that a counterparty will fail to discharge an obligation, causing a financial loss. At December 31, 2014 and 2013, there were no significant concentrations of credit risk with respect to any class of financial assets. The Company's revenue is earned from a broad base of customers. As a result, Hydro One did not earn a significant amount of revenue from any single customer. At December 31, 2014 and 2013, there was no significant accounts receivable balance due from any single customer.

At December 31, 2014, the Company's provision for bad debts was $66 million (2013 – $36 million). Adjustments and write-offs were determined on the basis of a review of overdue accounts, taking into consideration historical experience. At December 31, 2014, approximately 6% of the Company's net accounts receivable were aged more than 60 days (2013 – 4%).

Hydro One manages its counterparty credit risk through various techniques including: entering into transactions with highly-rated counterparties; limiting total exposure levels with individual counterparties consistent with the Company's Board-approved Credit Risk Policy; entering into master agreements which enable net settlement and the contractual right of offset; and monitoring the financial condition of counterparties. In addition to payment netting language in master agreements, the Company establishes credit limits, margining thresholds and collateral requirements for each counterparty. Counterparty credit limits are based on an internal credit review that considers a variety of factors, including the results of a scoring model, leverage, liquidity, profitability, credit ratings and risk management capabilities. The determination of credit exposure for a particular counterparty is the sum of current exposure plus the potential future exposure with that counterparty. The current exposure is calculated as the sum of the principal value of money market exposures and the market value of all contracts that have a positive mark-to-market position on the measurement date. The Company would offset the positive market values against negative values with the same counterparty only where permitted by the existence of a legal netting agreement such as an International Swap Dealers Association master agreement. The potential future exposure represents a safety margin to protect against future fluctuations of interest rates, currencies, equities, and commodities. It is calculated based on factors developed by the Bank of International Settlements, following extensive historical analysis of random fluctuations of interest rates and currencies. To the extent that a counterparty's margining thresholds are exceeded, the counterparty is required to post collateral with the Company as specified in each agreement. The Company monitors current and forward credit exposure to counterparties both on an individual and an aggregate basis. The Company's credit risk for accounts receivable is limited to the carrying amounts on the Consolidated Balance Sheets.

Derivative financial instruments result in exposure to credit risk since there is a risk of counterparty default. The credit exposure of derivative contracts, before collateral, is represented by the fair value of contracts at the reporting date. At December 31, 2014, the counterparty credit risk exposure on the fair value of these interest-rate swap contracts was $3 million (2013 – $14 million). At December 31, 2014, Hydro One's credit exposure for all derivative instruments, and applicable payables and receivables, had a credit rating of investment grade, with five financial institutions as the counterparties. The credit exposure of three of the five counterparties accounted for more than 10% of the total credit exposure of derivative contracts.

Liquidity Risk

Liquidity risk refers to the Company's ability to meet its financial obligations as they come due. Hydro One meets its short-term liquidity requirements using cash and cash equivalents on hand, funds from operations, the issuance of commercial paper, and the revolving standby credit facility of $1,500 million. The short-term liquidity under the Commercial Paper Program, and anticipated levels of funds from operations should be sufficient to fund normal operating requirements.

At December 31, 2014, accounts payable and accrued liabilities in the amount of $784 million (2013 – $789 million) were expected to be settled in cash at their carrying amounts within the next 12 months.

At December 31, 2014, Hydro One had issued long-term debt in the principal amount of $8,923 million (2013 – $9,045 million). Principal repayments, interest payments and related weighted average interest rates are summarized by the number of years to maturity in the following table:

Years to Maturity	**Long-term Debt Principal Repayments** *(millions of Canadian dollars)*	**Interest Payments** *(millions of Canadian dollars)*	**Weighted Average Interest Rate** *(%)*
1 year	550	419	2.8
2 years	500	393	4.3
3 years	600	381	5.2
4 years	750	350	2.8
5 years	228	327	1.6
	2,628	1,870	3.5
6 – 10 years	900	1,522	3.6
Over 10 years	5,395	4,373	5.4
	8,923	7,765	4.7

14. CAPITAL MANAGEMENT

The Company's objectives with respect to its capital structure are to maintain effective access to capital on a long-term basis at reasonable rates, and to deliver appropriate financial returns. In order to ensure ongoing effective access to capital, the Company targets to maintain an "A" category long-term credit rating.

The Company considers its capital structure to consist of Shareholder's equity, preferred shares, long-term debt, and cash and cash equivalents. At December 31, 2014 and 2013, the Company's capital structure was as follows:

December 31 (millions of Canadian dollars)	**2014**	2013
Long-term debt payable within one year	**552**	756
Less: cash and cash equivalents	**100**	565
	452	191
Long-term debt	**8,373**	8,301
Preferred shares	**323**	323
Common shares	**3,314**	3,314
Retained earnings	**4,249**	3,787
	7,563	7,101
Total capital	**16,711**	15,916

The Company has customary covenants typically associated with long-term debt. Among other things, Hydro One's long-term debt and credit facility covenants limit the permissible debt to 75% of the Company's total capitalization, limit the ability to sell assets and impose a negative pledge provision, subject to customary exceptions. At December 31, 2014 and 2013, Hydro One was in compliance with all of these covenants and limitations.

15. PENSION AND POST-RETIREMENT AND POST-EMPLOYMENT BENEFITS

Hydro One has a defined benefit pension plan, a supplementary pension plan, and post-retirement and post-employment benefit plans. The defined benefit pension plan (Pension Plan) is contributory and covers all regular employees of Hydro One and its subsidiaries, except employees of Hydro One Brampton Networks and Norfolk Power. Employees of Hydro One Brampton Networks and Norfolk Power participate in the OMERS plan. The supplementary pension plan provides members of the Pension Plan with benefits that would have been earned and payable under the Pension Plan but for the limitations imposed by the *Income Tax Act* (Canada). The supplementary pension plan obligation is included with other post-retirement and post-employment benefit obligations on the Consolidated Balance Sheets.

The OMERS Plan

Hydro One contributions to the OMERS plan for the year ended December 31, 2014 were $2 million (2013 – $2 million). Company contributions payable at December 31, 2014 and included in accrued liabilities on the Consolidated Balance Sheets were less than $1 million (2013 – less than $1 million). Hydro One contributions do not represent more than 5% of total contributions to the OMERS plan, as indicated in OMERS' most recently available annual report for the year ended December 31, 2013.

At December 31, 2013, the OMERS plan was 88.2% funded, with an unfunded liability of $8,641 million. This unfunded liability could result in future payments by participating employers and members. Hydro One future contributions could be increased substantially if other entities withdraw from the plan.

Pension Plan, Post-Retirement and Post-Employment Plans

The Pension Plan provides benefits based on highest three-year average pensionable earnings. For new management employees who commenced employment on or after January 1, 2004, and for new Society of Energy Professionals-represented staff hired after November 17, 2005, benefits are based on highest five-year average pensionable earnings. After retirement, pensions are indexed to inflation.

Company and employee contributions to the Pension Plan are based on actuarial valuations performed at least every three years. Annual Pension Plan contributions for 2014 of $174 million (2013 – $160 million) were based on an actuarial valuation effective December 31, 2013 (2013 – effective December 31, 2011) and the expected level of pensionable earnings. Estimated annual Pension Plan contributions for 2015 and 2016 are approximately $174 million and $175 million, respectively, based on the actuarial valuation as at December 31, 2013 and projected levels of pensionable earnings. Future minimum contributions beyond 2016 will be based on an actuarial valuation effective no later than December 31, 2016. Contributions are payable one month in arrears. All of the contributions are expected to be in the form of cash.

Hydro One recognizes the overfunded or underfunded status of the Pension Plan, and post-retirement and post-employment benefit plans (Plans) as an asset or liability on its Consolidated Balance Sheets, with offsetting regulatory assets and liabilities as appropriate. The underfunded benefit obligations for the Plans, in the absence of regulatory accounting, would be recognized in AOCI. The impact of changes in assumptions used to measure pension, post-retirement and post-employment benefit obligations is generally recognized over the expected average remaining service period of the employees. The measurement date for the Plans is December 31.

Year ended December 31	Pension Benefits		Post-Retirement and Post-Employment Benefits	
(millions of Canadian dollars)	**2014**	2013	**2014**	2013
Change in projected benefit obligation				
Projected benefit obligation, beginning of year	**6,576**	6,507	**1,531**	1,459
Current service cost	**145**	170	**41**	40
Interest cost	**312**	278	**73**	63
Reciprocal transfers	**–**	1	**–**	–
Benefits paid	**(319)**	(317)	**(45)**	(44)
Net actuarial loss (gain)	**821**	(63)	**(18)**	13
Projected benefit obligation, end of year	**7,535**	6,576	**1,582**	1,531
Change in plan assets				
Fair value of plan assets, beginning of year	**5,731**	4,992	**–**	–
Actual return on plan assets	**703**	887	**–**	–
Reciprocal transfers	**–**	1	**–**	–
Benefits paid	**(319)**	(317)	**–**	–
Employer contributions	**174**	160	**–**	–
Employee contributions	**35**	30	**–**	–
Administrative expenses	**(25)**	(22)	**–**	–
Fair value of plan assets, end of year	**6,299**	5,731	**–**	–
Unfunded status	**1,236**	845	**1,582**	1,531

Hydro One presents its benefit obligations and plan assets net on its Consolidated Balance Sheets within the following line items:

	Pension Benefits		Post-Retirement and Post-Employment Benefits	
December 31 (millions of Canadian dollars)	**2014**	2013	**2014**	2013
Accrued liabilities	**–**	–	**49**	43
Pension benefit liability	**1,236**	845	**–**	–
Post-retirement and post-employment benefit liability	**–**	–	**1,533**	1,488
Unfunded status	**1,236**	845	**1,582**	1,531

The funded or unfunded status of the pension, post-retirement and post-employment benefit plans refers to the difference between the fair value of plan assets and the projected benefit obligations for the Plans. The funded/unfunded status changes over time due to several factors, including contribution levels, assumed discount rates and actual returns on plan assets.

The following table provides the projected benefit obligation (PBO), accumulated benefit obligation (ABO) and fair value of plan assets for the Pension Plan:

December 31 (millions of Canadian dollars)	**2014**	2013
PBO	**7,535**	6,576
ABO	**6,887**	5,998
Fair value of plan assets	**6,299**	5,731

On an ABO basis, the Pension Plan was funded at 91% at December 31, 2014 (2013 – 96%). On a PBO basis, the Pension Plan was funded at 84% at December 31, 2014 (2013 – 87%). The ABO differs from the PBO in that the ABO includes no assumption about future compensation levels.

Components of Net Periodic Benefit Costs

The following table provides the components of the net periodic benefit costs for the years ended December 31, 2014 and 2013 for the Pension Plan:

Year ended December 31 (millions of Canadian dollars)	**2014**	2013
Current service cost, net of employee contributions	**110**	141
Interest cost	**312**	278
Expected return on plan assets, net of expenses	**(369)**	(309)
Actuarial loss amortization	**103**	175
Prior service cost amortization	**2**	2
Net periodic benefit costs	**158**	287
Charged to results of operations[1]	**81**	72

[1] The Company follows the cash basis of accounting consistent with the inclusion of pension costs in OEB-approved rates. During the year ended December 31, 2014, pension costs of $174 million (2013 – $160 million) were attributed to labour, of which $81 million (2013 – $72 million) was charged to operations, and $93 million (2013 – $88 million) was capitalized as part of the cost of property, plant and equipment and intangible assets.

The following table provides the components of the net periodic benefit costs for the years ended December 31, 2014 and 2013 for the post-retirement and post-employment benefit plans:

Year ended December 31 (millions of Canadian dollars)	**2014**	2013
Current service cost, net of employee contributions	**41**	40
Interest cost	**73**	63
Actuarial loss amortization	**18**	27
Prior service cost amortization	**2**	3
Net periodic benefit costs	**134**	133
Charged to results of operations	**62**	58

Assumptions

The measurement of the obligations of the Plans and the costs of providing benefits under the Plans involves various factors, including the development of valuation assumptions and accounting policy elections. When developing the required assumptions, the Company considers historical information as well as future expectations. The measurement of benefit obligations and costs is impacted by several assumptions including the discount rate applied to benefit obligations, the long-term expected rate of return on plan assets, Hydro One's expected level of contributions to the Plans, the incidence of mortality, the expected remaining service period of plan participants, the level of compensation and rate of compensation increases, employee age, length of service, and the anticipated rate of increase of health care costs, among other factors. The impact of changes in assumptions used to measure the obligations of the Plans is generally recognized over the expected average remaining service period of the plan participants. In selecting the expected rate of return on plan assets, Hydro One considers historical economic indicators that impact asset returns, as well as expectations regarding future long-term capital market performance, weighted by target asset class allocations. In general, equity securities, real estate and private equity investments are forecasted to have higher returns than fixed-income securities.

The following weighted average assumptions were used to determine the benefit obligations at December 31, 2014 and 2013:

	Pension Benefits		Post-Retirement and Post-Employment Benefits	
Year ended December 31	**2014**	2013	**2014**	2013
Significant assumptions:				
Weighted average discount rate	**4.00%**	4.75%	**4.00%**	4.75%
Rate of compensation scale escalation (without merit)	**2.50%**	2.50%	**2.50%**	2.50%
Rate of cost of living increase	**2.00%**	2.00%	**2.00%**	2.00%
Rate of increase in health care cost trends[1]	**–**	–	**4.36%**	4.39%

[1] 6.52% per annum in 2015, grading down to 4.36% per annum in and after 2031 (2013 - 6.81% in 2014, grading down to 4.39% per annum in and after 2031)

The following weighted average assumptions were used to determine the net periodic benefit costs for the years ended December 31, 2014 and 2013. Assumptions used to determine current year-end benefit obligations are the assumptions used to estimate the subsequent year's net periodic benefit costs.

Year ended December 31	**2014**	2013
Pension Benefits:		
Weighted average expected rate of return on plan assets	**6.50%**	6.25%
Weighted average discount rate	**4.75%**	4.25%
Rate of compensation scale escalation (without merit)	**2.50%**	2.50%
Rate of cost of living increase	**2.00%**	2.00%
Average remaining service life of employees *(years)*	**11**	11
Post-Retirement and Post-Employment Benefits:		
Weighted average discount rate	**4.75%**	4.25%
Rate of compensation scale escalation (without merit)	**2.50%**	2.50%
Rate of cost of living increase	**2.00%**	2.00%
Average remaining service life of employees *(years)*	**12**	12
Rate of increase in health care cost trends[1]	**4.39%**	4.39%

[1] 6.81% per annum in 2014, grading down to 4.39% per annum in and after 2031 (2013 – 6.91% in 2013, grading down to 4.39% per annum in and after 2031)

The discount rate used to determine the current year pension obligation and the subsequent year's net periodic benefit costs is based on a yield curve approach. Under the yield curve approach, expected future benefit payments for each plan are discounted by a rate on a third party bond yield curve corresponding to each duration. The yield curve is based on "AA" long-term corporate bonds. A single discount rate is calculated that would yield the same present value as the sum of the discounted cash flows.

The effect of a 1% change in health care cost trends on the projected benefit obligation for the post-retirement and post-employment benefits at December 31, 2014 and 2013 is as follows:

December 31 (millions of Canadian dollars)	**2014**	2013
Projected benefit obligation:		
Effect of a 1% increase in health care cost trends	**248**	258
Effect of a 1% decrease in health care cost trends	**(193)**	(200)

The effect of a 1% change in health care cost trends on the service cost and interest cost for the post-retirement and post-employment benefits for the years ended December 31, 2014 and 2013 is as follows:

Year ended December 31 (millions of Canadian dollars)	**2014**	2013
Service cost and interest cost:		
Effect of a 1% increase in health care cost trends	**23**	21
Effect of a 1% decrease in health care cost trends	**(17)**	(16)

The following approximate life expectancies were used in the mortality assumptions to determine the projected benefit obligations for the pension and post-retirement and post-employment plans at December 31, 2014 and 2013:

December 31, 2014				December 31, 2013			
Life expectancy at 65 for a member currently at				Life expectancy at 65 for a member currently at			
Age 65		**Age 45**		Age 65		Age 45	
Male	**Female**	**Male**	**Female**	Male	Female	Male	Female
23	**25**	**24**	**26**	23	25	24	26

Estimated Future Benefit Payments

At December 31, 2014, estimated future benefit payments to the participants of the Plans were:

(millions of Canadian dollars)	Pension Benefits	Post-Retirement and Post-Employment Benefits
2015	305	50
2016	316	52
2017	328	54
2018	339	56
2019	350	59
2020 through to 2024	1,889	332
Total estimated future benefit payments through to 2024	3,527	603

Components of Regulatory Assets

A portion of actuarial gains and losses and prior service costs is recorded within regulatory assets on Hydro One's Consolidated Balance Sheets to reflect the expected regulatory inclusion of these amounts in future rates, which would otherwise be recorded in OCI. The following table provides the actuarial gains and losses and prior service costs recorded within regulatory assets:

Year ended December 31 (millions of Canadian dollars)	**2014**	2013
Pension Benefits:		
Actuarial loss (gain) for the year	**511**	(619)
Actuarial loss amortization	**(103)**	(175)
Prior service cost amortization	**(2)**	(2)
	406	(796)
Post-Retirement and Post-Employment Benefits:		
Actuarial loss (gain) for the year	**(18)**	13
Actuarial loss amortization	**(18)**	(27)
Prior service cost amortization	**(2)**	(3)
	(38)	(17)

The following table provides the components of regulatory assets that have not been recognized as components of net periodic benefit costs for the years ended December 31, 2014 and 2013:

Year ended December 31 (millions of Canadian dollars)	**2014**	2013
Pension Benefits:		
Prior service cost	**2**	3
Actuarial loss	**1,234**	842
	1,236	845
Post-Retirement and Post-Employment Benefits:		
Prior service cost	**–**	2
Actuarial loss	**273**	306
	273	308

The following table provides the components of regulatory assets at December 31 that are expected to be amortized as components of net periodic benefit costs in the following year:

	Pension Benefits		Post-Retirement and Post-Employment Benefits	
December 31 (millions of Canadian dollars)	**2014**	2013	**2014**	2013
Prior service cost	**2**	2	**–**	2
Actuarial loss	**119**	103	**10**	15
	121	105	**10**	17

Pension Plan Assets

Investment Strategy

On a regular basis, Hydro One evaluates its investment strategy to ensure that Pension Plan assets will be sufficient to pay Pension Plan benefits when due. As part of this ongoing evaluation, Hydro One may make changes to its targeted asset allocation and investment strategy. The Pension Plan is managed at a net asset level. The main objective of the Pension Plan is to sustain a certain level of net assets in order to meet the pension obligations of the Company. The Pension Plan fulfills its primary objective by adhering to specific investment policies outlined in its Summary of Investment Policies and Procedures (SIPP), which is reviewed and approved by the Audit, Finance and Pension Investment Committee of Hydro One's Board of Directors. The Company manages net assets by engaging knowledgeable external investment managers who are charged with the responsibility of investing existing funds and new funds (current year's employee and employer contributions) in accordance with the approved SIPP. The performance of the managers is monitored through a governance structure. Increases in net assets are a direct result of investment income generated by investments held by the Pension Plan and contributions to the Pension Plan by eligible employees and by the Company. The main use of net assets is for benefit payments to eligible Pension Plan members.

Pension Plan Asset Mix

At December 31, 2014, the Pension Plan target asset allocations and weighted average asset allocations were as follows:

	Target Allocation (%)	Pension Plan Assets (%)
Equity securities	60.0	60.9
Debt securities	35.0	35.9
Other[1]	5.0	3.2
	100.0	100.0

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[1] Other investments include real estate and infrastructure investments.

At December 31, 2014, the Pension Plan held no Hydro One corporate bonds (2013 – $15 million) and $340 million of debt securities of the Province (2013 – $217 million).

Concentrations of Credit Risk

Hydro One evaluated its Pension Plan's asset portfolio for the existence of significant concentrations of credit risk as at December 31, 2014 and 2013. Concentrations that were evaluated include, but are not limited to, investment concentrations in a single entity, concentrations in a type of industry, and concentrations in individual funds. At December 31, 2014 and 2013, there were no significant concentrations (defined as greater than 10% of plan assets) of risk in the Pension Plan's assets.

The Pension Plan manages its counterparty credit risk with respect to bonds by investing in investment-grade and government bonds and with respect to derivative instruments by transacting only with financial institutions rated at least "A+" by Standard and Poor's Rating Services Inc., DBRS Limited, and Fitch Ratings Inc., and "A1" by Moody's Investors Service Inc., and also by utilizing exposure limits to each counterparty and ensuring that exposure is diversified across counterparties. The risk of default on transactions in listed securities is considered minimal, as the trade will fail if either party to the transaction does not meet its obligation.

Fair Value Measurements

The following tables present the Pension Plan assets measured and recorded at fair value on a recurring basis and their level within the fair value hierarchy at December 31, 2014 and 2013:

December 31, 2014 (millions of Canadian dollars)	**Level 1**	**Level 2**	**Level 3**	**Total**
Pooled funds	**–**	**18**	**142**	**160**
Cash and cash equivalents	**166**	**–**	**–**	**166**
Short-term securities	**–**	**176**	**–**	**176**
Real estate	**–**	**–**	**2**	**2**
Corporate shares – Canadian	**1,008**	**–**	**–**	**1,008**
Corporate shares – Foreign	**2,766**	**–**	**–**	**2,766**
Bonds and debentures – Canadian	**–**	**1,799**	**–**	**1,799**
Bonds and debentures – Foreign	**–**	**211**	**–**	**211**
Total fair value of plan assets[1]	**3,940**	**2,204**	**144**	**6,288**

[1] At December 31, 2014, the total fair value of Pension Plan assets excludes $18 million of interest and dividends receivable, and $7 million relating to accruals for pension administration expense.

December 31, 2013 (millions of Canadian dollars)	Level 1	Level 2	Level 3	Total
Pooled funds	1	16	117	134
Cash and cash equivalents	150	–	–	150
Short-term securities	–	180	–	180
Real estate	–	–	2	2
Corporate shares – Canadian	943	–	–	943
Corporate shares – Foreign	2,708	–	–	2,708
Bonds and debentures – Canadian	–	1,416	–	1,416
Bonds and debentures – Foreign	–	186	–	186
Total fair value of plan assets[1]	3,802	1,798	119	5,719

[1] At December 31, 2013, the total fair value of Pension Plan assets excludes $19 million of interest and dividends receivable, and $7 million relating to accruals for pension administration expense.

See Note 13 – Fair Value of Financial Instruments and Risk Management for a description of levels within the fair value hierarchy.

Changes in the Fair Value of Financial Instruments Classified in Level 3

The following table summarizes the changes in fair value of financial instruments classified in Level 3 for the years ended December 31, 2014 and 2013. The Pension Plan classifies financial instruments as Level 3 when the fair value is measured based on at least one significant input that is not observable in the markets or due to lack of liquidity in certain markets. The gains and losses presented in the table below may include changes in fair value based on both observable and unobservable inputs.

Year ended December 31 (millions of Canadian dollars)	**2014**	2013
Fair value, beginning of year	**119**	106
Realized and unrealized gains	**30**	23
Purchases	**23**	–
Sales and disbursements	**(28)**	(10)
Fair value, end of year	**144**	119

There were no significant transfers between any of the fair value levels during the years ended December 31, 2014 and 2013.

The Company performs sensitivity analysis for fair value measurements classified in Level 3, substituting the unobservable inputs with one or more reasonably possible alternative assumptions. These sensitivity analyses resulted in negligible changes in the fair value of financial instruments classified in this level.

Valuation Techniques Used to Determine Fair Value

Pooled Funds

The pooled fund category mainly consists of private equity and infrastructure investments. Private equity investments represent private equity funds that invest in operating companies that are not publicly traded on a stock exchange. Investment strategies in private equity include limited partnerships in businesses that are characterized by high internal growth and operational efficiencies, venture capital, leveraged buyouts and special situations such as distressed investments. Infrastructure investments represent infrastructure funds that invest in real assets which are not publicly traded on a stock exchange. Investment strategies in infrastructure include limited partnerships in core infrastructure assets focusing on assets that generate stable, long-term cash flows and deliver incremental returns relative to conventional fixed-income investments. Private equity and infrastructure valuations are reported by the fund manager and are based on the valuation of the underlying investments which includes inputs such as cost, operating results, discounted future cash flows and market-based comparable data. Since these valuation inputs are not highly observable, private equity and infrastructure investments have been categorized as Level 3 within pooled funds.

Cash Equivalents

Demand cash deposits held with banks and cash held by the investment managers are considered cash equivalents and are included in the fair value measurements hierarchy as Level 1.

Short-Term Securities

Short-term securities are valued at cost plus accrued interest, which approximates fair value due to their short-term nature. Short-term securities have been categorized as Level 2.

Real Estate

Real estate investments represent private equity investments in holding companies that invest in real estate properties. The investments in the holding companies are valued using net asset values reported by the fund manager. Real estate investments are categorized as Level 3.

Corporate Shares

Corporate shares are valued based on quoted prices in active markets and are categorized as Level 1. Investments denominated in foreign currencies are translated into Canadian currency at year-end rates of exchange.

Bonds and Debentures

Bonds and debentures are presented at published closing trade quotations, and are categorized as Level 2.

16. ENVIRONMENTAL LIABILITIES

The following tables show the movements in environmental liabilities for the years ended December 31, 2014 and 2013:

Year ended December 31, 2014 (millions of Canadian dollars)	**PCB**	**LAR**	**Total**
Environmental liabilities, January 1	**201**	**65**	**266**
Interest accretion	**9**	**2**	**11**
Expenditures	**(5)**	**(13)**	**(18)**
Revaluation adjustment	**(33)**	**13**	**(20)**
Environmental liabilities, December 31	**172**	**67**	**239**
Less: current portion	**8**	**10**	**18**
	164	**57**	**221**

Year ended December 31, 2013 (millions of Canadian dollars)	PCB	LAR	Total
Environmental liabilities, January 1	197	52	249
Interest accretion	9	1	10
Expenditures	(2)	(14)	(16)
Revaluation adjustment	(3)	26	23
Environmental liabilities, December 31	201	65	266
Less: current portion	15	12	27
	186	53	239

The following tables show the reconciliation between the undiscounted basis of the environmental liabilities and the amount recognized on the Consolidated Balance Sheets after factoring in the discount rate:

December 31, 2014 (millions of Canadian dollars)	**PCB**	**LAR**	**Total**
Undiscounted environmental liabilities	**195**	**70**	**265**
Less: discounting accumulated liabilities to present value	**23**	**3**	**26**
Discounted environmental liabilities	**172**	**67**	**239**

December 31, 2013 (millions of Canadian dollars)	PCB	LAR	Total
Undiscounted environmental liabilities	237	68	305
Less: discounting accumulated liabilities to present value	36	3	39
Discounted environmental liabilities	201	65	266

At December 31, 2014, the estimated future environmental expenditures were as follows:

(millions of Canadian dollars)	
2015	18
2016	37
2017	36
2018	35
2019	33
Thereafter	106
	265

At December 31, 2014, of the total estimated future environmental expenditures, $195 million relates to PCBs (2013 – $237 million) and $70 million relates to LAR (2013 – $68 million).

Hydro One records a liability for the estimated future expenditures for the contaminated LAR and for the phase-out and destruction of PCB-contaminated mineral oil removed from electrical equipment when it is determined that future environmental remediation expenditures are probable under existing statute or regulation and the amount of the future expenditures can be reasonably estimated.

There are uncertainties in estimating future environmental costs due to potential external events such as changes in legislation or regulations, and advances in remediation technologies. In determining the amounts to be recorded as environmental liabilities, the Company estimates the current cost of completing required work and makes assumptions as to when the future expenditures will actually be incurred, in order to generate future cash flow information. A long-term inflation rate assumption of approximately 2% has been used to express these current cost estimates as estimated future expenditures. Future expenditures have been discounted using factors ranging from approximately 2.3% to 6.3%, depending on the appropriate rate for the period when expenditures are expected to be incurred. All factors used in estimating the Company's environmental liabilities represent management's best estimates of the present value of costs required to meet existing legislation or regulations. However, it is reasonably possible that numbers or volumes of contaminated assets, cost estimates to perform work, inflation assumptions and the assumed pattern of annual cash flows may differ significantly from the Company's current assumptions. In addition, with respect to the PCB environmental liability, the availability of critical resources such as skilled labour and replacement assets and the ability to take maintenance outages in critical facilities may influence the timing of expenditures.

PCBs

The Environment Canada regulations, enacted under the *Canadian Environmental Protection Act, 1999*, govern the management, storage and disposal of PCBs based on certain criteria, including type of equipment, in-use status, and PCB-contamination thresholds. Under current regulations, Hydro One's PCBs have to be disposed of by the end of 2025, with the exception of specifically exempted equipment. Contaminated equipment will generally be replaced, or will be decontaminated by removing PCB-contaminated insulating oil and retro filling with replacement oil that contains PCBs in concentrations of less than 2 ppm.

The Company's best estimate of the total estimated future expenditures to comply with current PCB regulations is $195 million. These expenditures are expected to be incurred over the period from 2015 to 2025. As a result of its annual review of environmental liabilities, the Company recorded a revaluation adjustment in 2014 to reduce the PCB environmental liability by $33 million (2013 – $3 million).

LAR

The Company's best estimate of the total estimated future expenditures to complete its LAR program is $70 million. These expenditures are expected to be incurred over the period from 2015 to 2023. As a result of its annual review of environmental liabilities, the Company recorded a revaluation adjustment in 2014 to increase the LAR environmental liability by $13 million (2013 – $26 million).

17. ASSET RETIREMENT OBLIGATIONS

Hydro One records a liability for the estimated future expenditures for the removal and disposal of asbestos-containing materials installed in some of its facilities and for the decommissioning of specific switching stations located on unowned sites. AROs, which represent legal obligations associated with the retirement of certain tangible long-lived assets, are computed as the present value of the projected expenditures for the future retirement of specific assets and are recognized in the period in which the liability is incurred, if a reasonable estimate of fair value can be made. If the asset remains in service at the recognition date, the present value of the liability is added to the carrying amount of the associated asset in the period the liability is incurred and this additional carrying amount is depreciated over the remaining life of the asset. If an ARO is recorded in respect of an out-of-service asset, the asset retirement cost is charged to results of operations. Subsequent to the initial recognition, the liability is adjusted for any revisions to the estimated future cash flows associated with the ARO, which can occur due to a number of factors including, but not limited to, cost escalation, changes in technology applicable to the assets to be retired, changes in legislation or regulations, as well as for accretion of the liability due to the passage of time until the obligation is settled. Depreciation expense is adjusted prospectively for any increases or decreases to the carrying amount of the associated asset.

In determining the amounts to be recorded as AROs, the Company estimates the current fair value for completing required work and makes assumptions as to when the future expenditures will actually be incurred, in order to generate future cash flow information. A long-term inflation assumption of approximately 2% has been used to express these current cost estimates as estimated future expenditures. Future expenditures have been discounted using factors ranging from approximately 3.0% to 5.0%, depending on the appropriate rate for the period when expenditures are expected to be incurred. All factors used in estimating the Company's AROs represent management's best estimates of the cost required to meet existing legislation or regulations. However, it is reasonably possible that numbers or volumes of contaminated assets, cost estimates to perform work, inflation assumptions and the assumed pattern of annual cash flows may differ significantly from the Company's current assumptions. AROs are reviewed annually or more frequently if significant changes in regulations or other relevant factors occur. Estimate changes are accounted for prospectively.

At December 31, 2014, Hydro One had recorded AROs of $9 million (2013 – $14 million), consisting of $8 million (2013 – $7 million) related to the estimated future expenditures associated with the removal and disposal of asbestos-containing materials installed in some of its facilities, as well as $1 million (2013 – $7 million) related to the future decommissioning and removal of two switching stations. The amount of interest recorded is nominal.

18. SHARE CAPITAL

Preferred Shares

The Company has 12,920,000 issued and outstanding 5.5% cumulative preferred shares with a redemption value of $25 per share or $323 million total value. The Company is authorized to issue an unlimited number of preferred shares.

The Company's preferred shares are entitled to an annual cumulative dividend of $18 million, or $1.375 per share, which is payable on a quarterly basis. The preferred shares are not subject to mandatory redemption (except on liquidation) but are redeemable in certain circumstances. The shares are redeemable at the option of the Province at the redemption value, plus any accrued and unpaid dividends, if the Province sells a number of the common shares which it owns to the public such that the Province's holdings are reduced to less than 50% of the common shares of the Company. Hydro One may elect, without condition, to pay all or part of the redemption price by issuing additional common shares to the Province. If the Province does not exercise its redemption right, the Company would have the ability to adjust the dividend on the preferred shares to produce a yield that is 0.50% less than the then-current dividend market yield for similarly rated preferred shares. The preferred shares do not carry voting rights, except in limited circumstances, and would rank in priority over the common shares upon liquidation.

These preferred shares have conditions for their redemption that are outside the control of the Company because the Province can exercise its right to redeem in the event of change in ownership without approval of the Company's Board of Directors. Because the conditional redemption feature is outside the control of the Company, the preferred shares are classified outside of equity on the Consolidated Balance Sheets. Management believes that it is not probable that the preferred shares will become redeemable. No adjustment to the carrying value of the preferred shares has been recognized at December 31, 2014. If it becomes probable in the future that the preferred shares will be redeemed, the redemption value would be adjusted.

Common Shares

The Company has 100,000 issued and outstanding common shares. The Company is authorized to issue an unlimited number of common shares.

Common share dividends are declared at the sole discretion of the Hydro One Board of Directors, and are recommended by management based on results of operations, maintenance of the deemed regulatory capital structure, financial conditions, cash requirements, and other relevant factors, such as industry practice and Shareholder expectations.

Earnings per Share

Basic and diluted earnings per share have been calculated on the basis of net income attributable to the Shareholder of Hydro One and the weighted average number of common shares outstanding during the year.

19. DIVIDENDS

In 2014, preferred share dividends in the amount of $18 million (2013 – $18 million) and common share dividends in the amount of $269 million (2013 – $200 million) were declared.

20. RELATED PARTY TRANSACTIONS

Hydro One is owned by the Province. The OEFC, IESO, OPA, Ontario Power Generation Inc. (OPG) and the OEB are related parties to Hydro One because they are controlled or significantly influenced by the Province.

The Province

During 2014, Hydro One paid dividends to the Province totalling $287 million (2013 – $218 million).

In November 2014, the Company redeemed the $250 million Province of Ontario Floating-Rate Notes held as a long-term investment. These notes were originally purchased in January 2010 with a maturity date of November 19, 2014.

IESO

In 2014, Hydro One purchased power in the amount of $2,601 million (2013 – $2,477 million) from the IESO-administered electricity market.

Hydro One receives revenues for transmission services from the IESO, based on OEB-approved uniform transmission rates. Transmission revenues for 2014 include $1,556 million (2013 – $1,509 million) related to these services.

Hydro One receives amounts for rural rate protection from the IESO. Distribution revenues for 2014 include $127 million (2013 – $127 million) related to this program.

Hydro One also receives revenues related to the supply of electricity to remote northern communities from the IESO. Distribution revenues for 2014 include $32 million (2013 – $33 million) related to these services.

OPA

The OPA funds substantially all of the Company's conservation and demand management programs. The funding includes program costs, incentives, and management fees. In 2014, Hydro One received $33 million (2013 – $34 million) from the OPA related to these programs.

OPG

In 2014, Hydro One purchased power in the amount of $23 million (2013 – $15 million) from OPG.

Hydro One has service level agreements with OPG. These services include field, engineering, logistics and telecommunications services. In 2014, revenues related to the provision of construction and equipment maintenance services with respect to these service level agreements were $12 million (2013 – $9 million), primarily for the Transmission Business. Operation, maintenance and administration costs in 2014 related to the purchase of services with respect to these service level agreements were $1 million (2013 – $1 million).

OEFC

In 2014, Hydro One made payments in lieu of corporate income taxes to the OEFC totalling $86 million (2013 – $138 million).

In 2014, Hydro One purchased power in the amount of $9 million (2013 – $8 million) from power contracts administered by the OEFC.

Hydro One pays a $5 million annual fee to the OEFC for indemnification against adverse claims in excess of $10 million paid by the OEFC with respect to certain of Ontario Hydro's businesses transferred to Hydro One on April 1, 1999.

PILs and payments in lieu of property taxes are paid to the OEFC.

OEB

Under the *Ontario Energy Board Act, 1998*, the OEB is required to recover all of its annual operating costs from gas and electricity distributors and transmitters. In 2014, Hydro One incurred $12 million (2013 – $12 million) in OEB fees.

Sales to and purchases from related parties occur at normal market prices or at a proxy for fair value based on the requirements of the OEB's Affiliate Relationships Code. Outstanding balances at period end are interest free and settled in cash.

The amounts due to and from related parties as a result of the transactions referred to above are as follows:

December 31 (millions of Canadian dollars)	**2014**	2013
Due from related parties	**224**	197
Due to related parties[1]	**(227)**	(230)
Investment	**–**	251

[1] Included in due to related parties at December 31, 2014 are amounts owing to the IESO in respect of power purchases of $214 million (2013 – $217 million).

21. CONSOLIDATED STATEMENTS OF CASH FLOWS

The changes in non-cash balances related to operations consist of the following:

Year ended December 31 (millions of Canadian dollars)	**2014**	2013
Accounts receivable	**(93)**	(78)
Due from related parties	**(27)**	(43)
Prepaid expenses and other assets	**(13)**	(5)
Accounts payable	**39**	13
Accrued liabilities	**(35)**	71
Due to related parties	**(3)**	(31)
Accrued interest	**–**	5
Long-term accounts payable and other liabilities	**(3)**	(5)
Post-retirement and post-employment benefit liability	**80**	84
	(55)	11

Capital Expenditures

The following table illustrates the reconciliation between investments in property, plant and equipment and the amount presented in the Consolidated Statements of Cash Flows after factoring in capitalized depreciation and the net change in related accruals:

Year ended December 31 (millions of Canadian dollars)	**2014**	2013
Capital investments in property, plant and equipment	**(1,511)**	(1,312)
Capitalized depreciation and net change in accruals included in capital investments in property, plant and equipment	**30**	4
Capital expenditures – property, plant and equipment	**(1,481)**	(1,308)

The following table illustrates the reconciliation between investments in intangible assets and the amount presented in the Consolidated Statements of Cash Flows after factoring in the net change in related accruals:

Year ended December 31 (millions of Canadian dollars)	**2014**	2013
Capital investments in intangible assets	**(19)**	(82)
Net change in accruals included in capital investments in intangible assets	**(4)**	3
Capital expenditures – intangible assets	**(23)**	(79)

Supplementary Information

Year ended December 31 (millions of Canadian dollars)	**2014**	2013
Net interest paid	**412**	395
PILs	**86**	138

22. CONTINGENCIES

Legal Proceedings

Hydro One is involved in various lawsuits, claims and regulatory proceedings in the normal course of business. In the opinion of management, the outcome of such matters will not have a material adverse effect on the Company's consolidated financial position, results of operations or cash flows.

Transfer of Assets

The transfer orders by which the Company acquired certain of Ontario Hydro's businesses as of April 1, 1999 did not transfer title to some assets located on Reserves (as defined in the *Indian Act* (Canada)). Currently, the OEFC holds these assets. Under the terms of the transfer orders, the Company is required to manage these assets until it has obtained all consents necessary to complete the transfer of title of these assets to itself. The Company cannot predict the aggregate amount that it may have to pay, either on an annual or one-time basis, to obtain the required consents. In 2014, the Company paid approximately $1 million (2013 – $2 million) in respect of these consents. If the Company cannot obtain the required consents, the OEFC will continue to hold these assets for an indefinite period of time. If the Company cannot reach a satisfactory settlement, it may have to relocate these assets to other locations at a cost that could be substantial or, in a limited number of cases, to abandon a line and replace it with diesel-generation facilities. The costs relating to these assets could have a material adverse effect on the Company's results of operations if the Company is not able to recover them in future rate orders.

23. COMMITMENTS

Outsourcing Agreements

The current agreement with Inergi LP (Inergi), an affiliate of Capgemini Canada Inc., expires on February 28, 2015. On November 28, 2014, Hydro One entered into an agreement with Inergi (Inergi Agreement), the service provider selected through a competitive procurement process which began in 2013, for second-generation back office and IT outsourcing services for a term of 58 months, commencing March 1, 2015 to December 31, 2019. Under the agreement, Inergi will provide Hydro One with settlements, source to pay services, pay operations services, information technology and finance and accounting services. Coincident with the conclusion of negotiations on the Inergi Agreement, Hydro One reached agreement with Inergi for the provision of second-generation customer service operations outsourcing services for a fixed period of three years beginning March 1, 2015 to February 28, 2018.

In September 2014, Hydro One entered into an agreement with Brookfield Johnson Controls Canada LP (Brookfield) for facilities management services for a term of ten years, from January 1, 2015 to December 31, 2024, with the option to renew for an additional term of three years. Under the agreement, Brookfield will provide us with facilities management and execution of certain capital projects as deemed required by the Company. The Brookfield Agreement has a value of up to approximately $658 million over the ten-year term of the agreement, including the facilities management portion of the contract, plus a variable amount of capital work depending on the needs that may arise as determined by the Company, with no minimum capital work guarantee. The agreement also includes a fixed management fee of approximately $2 million for each year of the term.

At December 31, 2014, the annual commitments under the outsourcing agreements were as follows: 2015 – $179 million; 2016 – $146 million; 2017 – $145 million; 2018 – $113 million; 2019 – $105 million; and thereafter – $13 million.

Prudential Support

Purchasers of electricity in Ontario, through the IESO, are required to provide security to mitigate the risk of their default based on their expected activity in the market. As at December 31, 2014, the Company provided prudential support to the IESO on behalf of its subsidiaries using parental guarantees of $330 million (2013 – $325 million), and on behalf of two distributors using guarantees of $1 million (2013 – $1 million). In addition, as at December 31, 2014, the Company has provided letters of credit in the amount of $8 million (2013 – $21 million) to the IESO. The IESO could draw on these guarantees and/or letters of credit if these subsidiaries or distributors fail to make a payment required by a default notice issued by the IESO. The maximum potential payment is the face value of any letters of credit plus the amount of the parental guarantees.

Retirement Compensation Arrangements

Bank letters of credit have been issued to provide security for the Company's liability under the terms of a trust fund established pursuant to the supplementary pension plan for eligible employees of Hydro One. The supplementary pension plan trustee is required to draw upon these letters of credit if Hydro One is in default of its obligations under the terms of this plan. Such obligations include the requirement to provide the trustee with an annual actuarial report as well as letters of credit sufficient to secure the Company's liability under the plan, to pay benefits payable under the plan and to pay the letter of credit fee. The maximum potential payment is the face value of the letters of credit. At December 31, 2014, Hydro One had letters of credit of $126 million (2013 – $127 million) outstanding relating to retirement compensation arrangements.

Operating Leases

Hydro One is committed as lessee to irrevocable operating lease contracts for buildings used in administrative and service-related functions and storing telecommunications equipment. These leases have a typical term of between three and five years, but several leases have lesser or greater terms to address special circumstances and/or opportunities. Renewal options, which are generally prevalent in most leases, have similar terms of three to five years. All leases include a clause to enable upward revision of the rental charge on an annual basis or on renewal according to prevailing market conditions or pre-established rents. There are no restrictions placed upon Hydro One by entering into these leases. Hydro One Networks and Hydro One Telecom are the principal entities concerned.

During the year ended December 31, 2014, the Company made lease payments totalling $11 million (2013 – $11 million). At December 31, 2014, the future minimum lease payments under non-cancellable operating leases were as follows: 2015 – $7 million; 2016 – $10 million; 2017 – $9 million; 2018 – $7 million; 2019 – $3 million; and thereafter – $9 million.

24. SEGMENTED REPORTING

Hydro One has three reportable segments:

- The Transmission Business, which comprises the core business of providing electricity transportation and connection services, is responsible for transmitting electricity throughout the Ontario electricity grid;
- The Distribution Business, which comprises the core business of delivering and selling electricity to customers; and
- Other, which includes certain corporate activities and the operations of the telecommunications business.

The designation of segments has been based on a combination of regulatory status and the nature of the products and services provided. Operating segments of the Company are determined based on information used by the chief operating decision maker in deciding how to allocate resources and evaluate the performance of each of the segments. The Company evaluates segment performance based on income before financing charges and provision for PILs from continuing operations (excluding certain allocated corporate governance costs).

The accounting policies followed by the segments are the same as those described in the summary of significant accounting policies (see Note 2 – Significant Accounting Policies). Segment information on the above basis is as follows:

Year ended December 31, 2014 *(millions of Canadian dollars)*	**Transmission**	**Distribution**	**Other**	**Consolidated**
Revenues	**1,588**	**4,903**	**57**	**6,548**
Purchased power	**–**	**3,419**	**–**	**3,419**
Operation, maintenance and administration	**394**	**742**	**56**	**1,192**
Depreciation and amortization	**346**	**367**	**9**	**722**
Income (loss) before financing charges and provision for PILs	**848**	**375**	**(8)**	**1,215**
Capital investments	**845**	**680**	**5**	**1,530**

Year ended December 31, 2013 *(millions of Canadian dollars)*	Transmission	Distribution	Other	Consolidated
Revenues	1,529	4,484	61	6,074
Purchased power	–	3,020	–	3,020
Operation, maintenance and administration	375	672	59	1,106
Depreciation and amortization	327	340	9	676
Income (loss) before financing charges and provision for PILs	827	452	(7)	1,272
Capital investments	714	673	7	1,394

Total Assets by Segment:

December 31 (millions of Canadian dollars)	**2014**	2013
Transmission	**12,540**	11,846
Distribution	**9,805**	8,805
Other	**205**	974
Total assets	**22,550**	21,625

All revenues, costs and assets, as the case may be, are earned, incurred or held in Canada.

25. SUBSEQUENT EVENT

On February 11, 2015, preferred share dividends in the amount of $4 million and common share dividends in the amount of $25 million were declared.

COMMUNITY

The Electricity Discovery Centre travelled more than 12,000 kilometres between September 2013 and September 2014 – the equivalent of driving from Halifax to Vancouver and back.

13 women were awarded the Women in Engineering Scholarship

95%

of visitors

would recommend visiting the Electricity Discovery Centre to family and friends

YOUR COMMUNITY IS OUR COMMUNITY

From a partnership with a Northern Ontario college to the 12,000 kilometres travelled by our Electricity Discovery Centre, our 2014 investments are investments in Ontario's future.

hydro one
Sustainable Electricity Company
Canadian Electricity Association

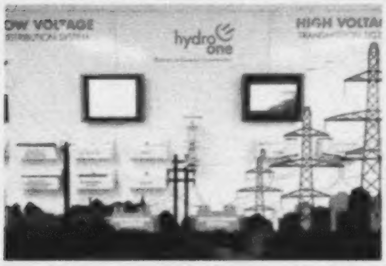
Jim Burpee, President and CEO of the Canadian Electricity Association, presents Carmine Marcello, President and CEO of Hydro One, with the Sustainable Electricity Company designation.

SUSTAINABLE ELECTRICITY COMPANY DESIGNATION

In December, the Canadian Electricity Association (CEA) awarded Hydro One with the Sustainable Electricity Company™ designation for our commitment to corporate responsibility and sustainable business practices. The designation recognizes the outstanding work Hydro One employees do in delivering electricity in a sustainable and socially responsible manner and in meeting the high expectations of our customers and the people of Ontario.

WOMEN IN ENGINEERING SCHOLARSHIP

Hydro One has a long history of helping female students who are pursuing non-traditional careers. In October, we launched the Women in Engineering Scholarship for up to 15 women studying engineering at the undergraduate level in accredited Ontario universities. Winners receive a financial reward, plus a paid work placement with Hydro One.



ELECTRICITY DISCOVERY CENTRE

September marked the first anniversary of our Electricity Discovery Centre, a mobile educational trailer that travels across the province to inform and educate the people of Ontario about energy consumption, electrical safety and the role Hydro One plays in their communities. Between September 2013 and September 2014, the Electricity Discovery Centre travelled more than 12,000 kilometres, attended 28 fairs and welcomed more than 27,500 visitors from across Ontario.

CONFEDERATION COLLEGE PARTNERSHIP

In January, Hydro One announced funding for a pre-apprenticeship program with Confederation College. The $750,000 investment will support recruiting and training residents of Northern Ontario, with particular emphasis on peoples from Treaty 9 First Nations communities, in readiness for electrical technology and technician apprenticeships. The program will help build local trades capacity across Northern Ontario and is well aligned with the existing Hydro One College Consortium that focuses on curriculum development for electrical trades.

LEONARD S. (TONY) MANDAMIN SCHOLARSHIP AWARD

In June, Hydro One recognized eight outstanding Aboriginal students as the 2014 recipients of the Leonard S. (Tony) Mandamin Scholarship Award. The scholarship was renamed in 2014 to recognize the achievements of the Honourable Justice Leonard S. (Tony) Mandamin, who was one of Ontario's first electrical engineering graduates of First Nations ancestry. The recipients of this award are offered a work term with Hydro One and receive financial support to aid in their academic studies.

THE WILLIAM PEYTON HUBBARD MEMORIAL AWARD

In May, Hydro One awarded two outstanding black students with the William Peyton Hubbard Memorial Award for their studies in disciplines related to our industry. The award honours William Peyton Hubbard, Toronto's first black councillor and advocate of publicly owned electricity, who with Sir Adam Beck, brought electrical power to the people of Ontario.

HYDRO ONE EMPLOYEES' AND PENSIONERS' CHARITY CAMPAIGN

The Company's charity campaign raised more than $1.3 million in 2014 for hundreds of charities across Ontario, surpassing 2013's contribution of $1.24 million. To date, more than 1,780 charities have benefited from the campaign.

BOARD OF DIRECTORS
(as at December 31, 2014)

Sandra Pupatello[6]
Chair of the Board of
Directors, Hydro One Inc.

Director, Business
Development and Global
Markets for PwC, Canada

Chief Executive Officer
WindsorEssex Economic
Development Corporation

Kathryn A. Bouey[2,3,4]
President,
TBG Strategic
Services Inc.

Corporate Director

Sally Daub[1,4]
President and Chief
Executive Officer,
ViXS Systems Inc.

Bill Limbrick[2,3]
Corporate Director

Tom Moss[3,5]
Corporate Director

Gale Rubenstein[2,4,5,6]
Partner,
Goodmans LLP

John Wiersma[3,5]
Corporate Director

Carmine Marcello[6]
President and
Chief Executive Officer,
Hydro One Inc.

George Cooke[1,2,6]
President, Martello
Associates Consulting

Chair of the Board of
Directors of OMERS
Administration Corporation

Catherine Karakatsanis[3,4,5]
Chief Operating Officer,
Morrison Hershfield
Group Inc.

Don MacKinnon[1,4,5]
President,
Power Workers' Union

Yezdi Pavri[1,2,6]
Corporate Director

Maureen Sabia[1,3]
Non-Executive Chairman
of the Board of Directors
of Canadian Tire
Corporation Limited

Carole Workman[1,4]
Corporate Director

Board Committees

[1] *Audit, Finance and Pension Investment Committee* In May 2014, the Audit and Finance (AF) Committee amalgamated with the Investment-Pension (IP) Committee to form the Audit, Finance and Pension Investment Committee (AFPIC). The Committee oversees the integrity of accounting policies and financial reporting, internal controls, internal audit, financial risk exposures, financial compliance and ethics policies. In addition, the Committee assists the Board in fulfilling its oversight responsibilities in all matters related to the Hydro One Pension Plan including the Hydro One Pension Fund. The AF Committee met four times in 2014, the IP Committee met one time in 2014, and the AFPIC met five times in 2014.

[2] *Corporate Governance and Human Resources Committee* In May 2014, the Corporate Governance (CG) Committee amalgamated with the Human Resources (HR) Committee to form the Corporate Governance and Human Resources Committee (CGHR). The Committee is responsible for the Board's governance of the Company. It recommends issues to be discussed at meetings of the Board of Directors, reviews the mandate of the Board and each committee of the Board, conducts Board Assessments, monitors the quality of management's relationship with the Board and recommends suitable nominees for election to the Board of Directors. In addition, the Committee is responsible for reviewing the appropriateness of the Company's current and future organizational structure, succession plans for senior corporate executive officers and divisional officers, the code of business conduct, and the performance and remuneration of senior executives, including recommending to the Board the remuneration of the President and CEO. The CG Committee met one time in 2014, the HR Committee met five times in 2014, and the CGHR Committee met nine times in 2014.

[3] *Business Transformation Committee* The Business Transformation Committee is responsible for assisting the Board in its oversight responsibilities in all matters related to the Company's Cornerstone Project, the Advanced Distribution System (Smart Grid) and Continuous Innovation Strategy, and the planning, development and implementation of major transmission system or distribution projects, including projects described in the Corporation's Green Energy Implementation Plan. The Committee met fourteen times in 2014.

[4] *Regulatory and Public Policy Committee* The Regulatory and Public Policy Committee monitors the Company's compliance with applicable regulatory requirements and legislation, and is responsible for identifying, assessing and providing advice to the Board of Directors on public affairs issues that have a significant impact on the Company. The Committee oversees compliance programs, policies, standards and procedures and reviews the Company's proposals for rate applications, compliance actions and reports. The Committee met four times in 2014.

[5] *Health, Safety and Environment Committee* The Health, Safety and Environment Committee is responsible for reviewing occupational health, safety and environment policies, standards, and programs, compliance with occupational health, safety and environmental legislation, policies and standards, and public health and safety issues. The Committee met three times in 2014.

[6] *Strategy Committee* The Strategy Committee was established in May 2014 to assist the Board with matters relating to the Premier's Advisory Council on Government Assets. The Committee met four times in 2014.

Hydro One Inc.
Is a holding company with subsidiaries that operate in the business areas of electricity transmission and distribution, and telecom services.

Hydro One Networks Inc.
Represents the majority of our business, which is regulated by the Ontario Energy Board. It is involved in the planning, construction, operation and maintenance of our transmission and distribution networks.

Hydro One Brampton Networks Inc.
Distributes electricity to one of the fastest-growing urban centres in Canada, just 30 kilometres outside of Toronto.

Hydro One Remote Communities Inc.
Operates and maintains the generation and distribution assets used to supply electricity to 21 remote communities across Northern Ontario that are not connected to the province's electricity transmission grid.

Hydro One Telecom Inc.
Markets our fibre-optic capacity to business customers. This business represents less than one per cent of our total assets.

CORPORATE INFORMATION

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Toronto, Ontario M5G 2P5
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1-877-955-1155
www.HydroOne.com

Investor Relations
(416) 345-6867
investor.relations@HydroOne.com

Hydro One is a Securities and Exchange Commission (SEC) issuer in the United States. Hydro One's annual and quarterly filings, including Financial Statements, Management's Discussion and Analysis, Press Releases, Annual Information Form and Annual Report, can be found on SEDAR at www.sedar.com and on the United States' SEC website at www.sec.gov.

The documents can also be found on Hydro One's website at www.HydroOne.com under Investor Relations/Media.

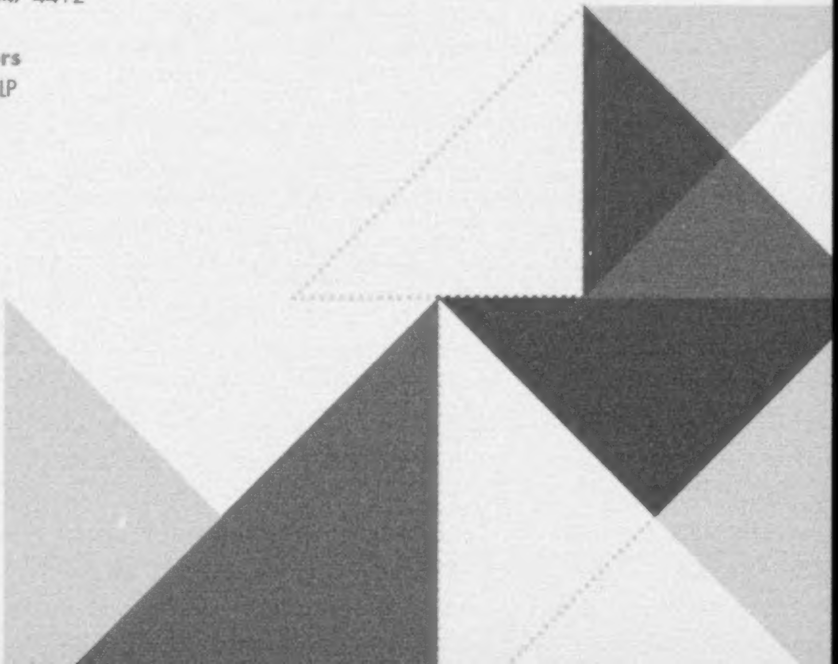
Media Inquiries
(416) 345-6868
1-877-506-7584

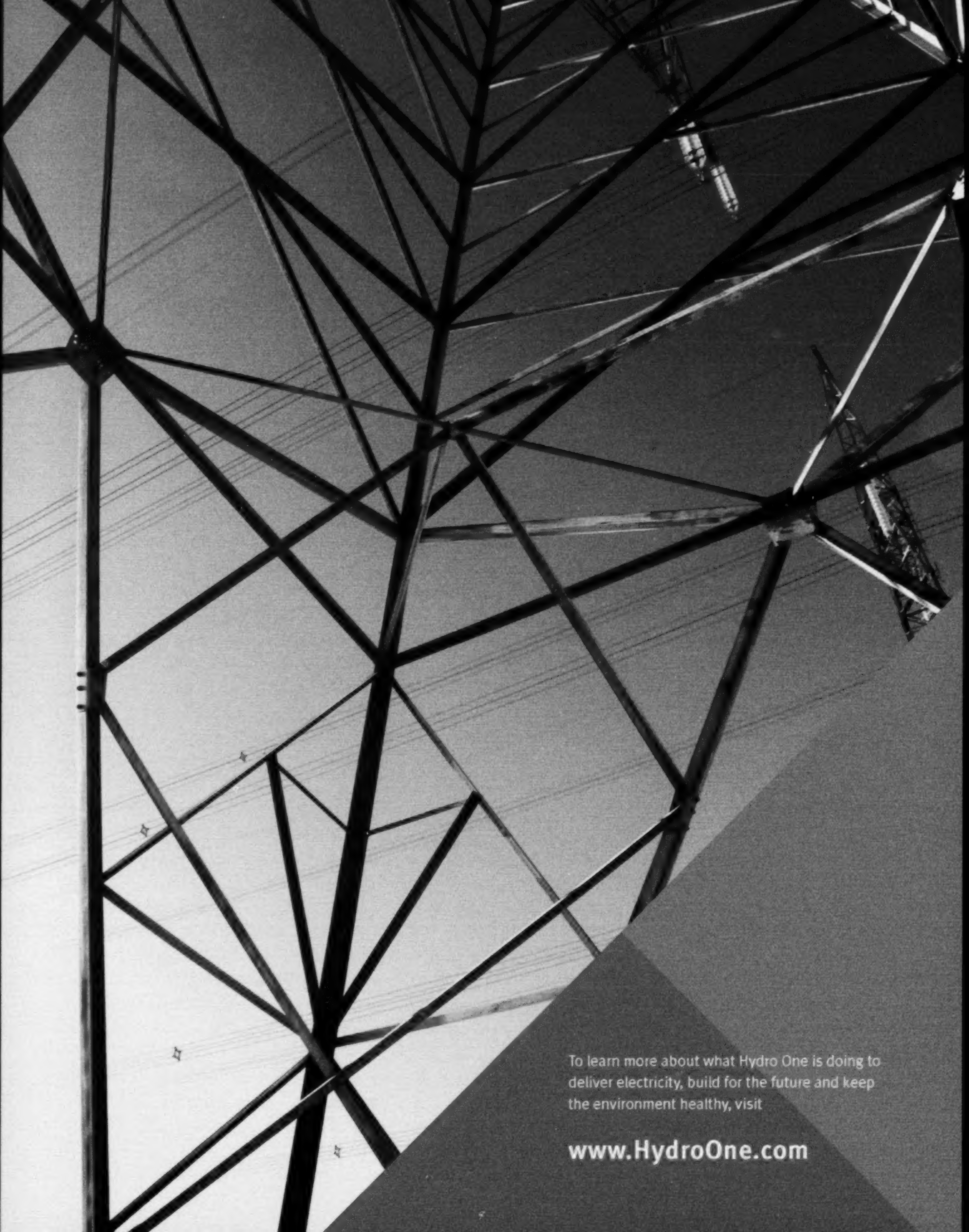
Customer Inquiries
Power outage and emergency number:
1-800-434-1235

Residential, farm and small business accounts:
1-888-664-9376

Business accounts:
1-877-447-4412

Auditors
KPMG LLP





To learn more about what Hydro One is doing to deliver electricity, build for the future and keep the environment healthy, visit

www.HydroOne.com